ONTARIO ENERGY BOARD

DER Valuation Review

Stakeholder Consultation Supporting Materials

November 24th, 2025

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Please note this document comprises of supporting materials for the DER Valuation Stakeholder Consultation to be held on November 24th, 2025.

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Part 1: DER Compensation

Existing Compensation Mechanism Eligibility

Existing Compensation Mechanism Eligibility

The DERs eligible to receive compensation under each mechanism in Ontario were identified as shown in Table 1 below.

Table 1. Eligible compensation mechanisms for each type of DER

Compensation Mechanisms available for net new DERs	FTM			BTM				
	Distributed Generation	Distributed Energy Storage	Hybrid	Distributed Generation	Distributed Energy Storage	Hybrid	Demand Response	Managed EV Charging
Energy Arbitrage					✓	✓		✓
Net Metering				✓		✓		
IESO Wholesale Energy Market	✓	✓	✓	✓*	✓*	✓*	✓*	
IESO Contracts	✓†	✓†	✓†					
IESO Capacity Auction	✓**	✓	✓	✓††	✓	✓	✓	
Industrial Conservation Initiative				✓	✓	✓	✓	✓
IESO eDSM Framework***				✓		✓	✓	
Distributor Contracts	✓	✓	✓	✓	✓	✓	✓	✓

*BTM resources typically do not participate in the wholesale energy market due to size restrictions. This represents aggregated BTM loads participating in the market.
**The IESO is aiming to enable eligible variable generation resources (such as solar) to qualify and offer their resource's capacity in the capacity auction.
***The IESO eDSM framework could potentially include other BTM resources in the future if offered.
† Subject to the eligibility requirements of each procurement round.
†† BTM generation is eligible to participate in the capacity auction under demand response because they can be used to offset consumption at a load site.

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Part 1: DER Compensation

Qualitative Analysis

Demand Response – Current Compensation

Table 2. Current compensation mechanisms and qualitative gap analysis for each DER type

Demand Response	Assessment of System Value	Current Compensation Mechanisms					
		Peak Perks – RPP Customers[2]	Hydro One MyRewards[3]	THESL LDR	Capacity Auction		Industrial Conservation Initiative
					RPP	Class A & Non-RPP Class B	
Generation capacity	*Value is **high***	*Participants receive $75 at registration + $20/year of participation.[1,2]*	*Mechanism does not compensate for generation capacity.*	*Mechanism does not compensate for generation capacity.*	*While lower than capacity payments in long-term contracts, the auction clearing price is determined by the bids received for each commitment period. Participants earned approx. $240/MW-business day from May 01, 2023, through Apr 30, 2025.[1]*		*Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	*For DERs that provide this value, mechanism does not compensate for transmission and distribution capacity.*	*Mechanism does not compensate for transmission capacity.*	*Includes a local capacity auction for demand response for the summer period. Any bids below the maximum capacity price are selected for participation. Price includes a distribution value and a transmission adder.*	*For DERs that provide this value, mechanism does not compensate for transmission and distribution capacity.*		
Distribution capacity			*Participants receive $75 at registration.[3]*				
Energy	*Value is **low***	*Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable retail rates.[1]*		*Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable wholesale market price.*	*Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable retail rates.[1]*	*Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable wholesale market price.*	
Emissions	*Value is **low***	*For DERs that provide this value, mechanism does not compensate for emissions.*					

1. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.
2. https://saveonenergy.ca/For-Your-Home/Peak-Perks
3. Under Hydro One's myEnergy Rewards program, customers receive similar compensation ($75 upfront incentive) which can be attributed to distribution capacity instead as the program is limited to Hydro One's residential customers.

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Demand Response – Gap Identification

Table 2. – cont.

<table>
<tr><th rowspan="2">Demand Response</th><th rowspan="2">Assessment of System Value</th><th colspan="5">Current Compensation Mechanisms</th></tr>
<tr><th>Peak Perks – RPP Customers[2]</th><th>Hydro One MyRewards[3]</th><th>THESL LDR</th><th>Capacity Auction
RPP</th><th>Capacity Auction
Class A & Non-RPP Class B</th><th>Industrial Conservation Initiative</th></tr>
<tr><td>Generation capacity</td><td>Value is high</td><td>Participants receive $75 at registration + $20/year of participation.[1,2]</td><td colspan="2">For DERs that provide this value, there may be a gap in compensation</td><td>While lower than capacity payments in long-term contracts, the auction clearing price is determined by the bids received for each commitment period. Participants earned approx. $240/MW-business day from May 01, 2023, through Apr 30, 2025.[1]</td><td>Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.</td></tr>
<tr><td>Transmission capacity</td><td rowspan="2">Value is high in regions with Tx/Dx system constraints due to resource’s high UCAP and availability during bulk/local peak demand hours. Value is zero in regions without constraints.</td><td rowspan="2">For DERs that provide this value, there may be a gap in compensation</td><td>For DERs that provide this value, there may be a gap in compensation</td><td>Includes a local capacity auction for demand response for the summer period. Any bids below the maximum capacity price are selected for participation. Price includes a distribution value and a transmission adder.</td><td colspan="2" rowspan="2">For DERs that provide this value, there may be a gap in compensation</td></tr>
<tr><td>Distribution capacity</td><td>Participants receive $75 at registration.[3]</td></tr>
<tr><td>Energy</td><td>Value is low</td><td colspan="2">Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable retail rates.[1]</td><td>Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable wholesale market price.</td><td>Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable retail rates.[1]</td><td>Compensation is equal to the difference in user costs determined by the change in consumption during DR events and the applicable wholesale market price.</td></tr>
<tr><td>Emissions</td><td>Value is low</td><td colspan="5">For DERs that provide this value, there may be a gap in compensation</td></tr>
</table>

1. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.
2. https://saveonenergy.ca/For-Your-Home/Peak-Perks
3. Under Hydro One’s myEnergy Rewards program, customers receive similar compensation ($75 upfront incentive) which can be attributed to distribution capacity instead as the program is limited to Hydro One’s residential customers.

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Managed EV Charging – Current Compensation

Table 2. – cont.

Managed EV Charging	Assessment of System Value	Current Compensation Mechanisms[1]				
		Energy Arbitrage				Hydro One MyRewards
		RPP TOU	RPP ULO	RPP Tiered	Non-RPP Class B	
Generation capacity	*Value is **medium***	*Mechanism does not compensate for generation capacity.[2]*			*Compensation is zero since the GA rate does not vary by hour.*	*For DERs that provide this value, mechanism does not compensate for generation capacity.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints if charging is shifted away from bulk/local system peak demand periods. **Value is zero in regions without constraints.***	*For DERs that provide this value, mechanism does not compensate for transmission and distribution capacity.*				*Participants receive $50 at registration + $5 per month during which the participating device(s) has been called on and responds to curtail electricity demand for at least 50% of scheduled peak demand events*
Distribution capacity						
Energy	*Value is **low***	*Compensation is equal to the difference in user costs determined by the change in consumption due to managed charging and the applicable retail rates (for on-peak to off-peak this is approx. 2:1 for TOU and 10:1 for ULO).[2]*	*Compensation is zero since the retail rate does not vary by hour.*		*Compensation is equal to the difference in user costs determined by the change in consumption due to managed charging and the applicable wholesale market price.*	*For DERs that provide this value, mechanism does not compensate for energy.*
Emissions	*Value is **low***	*For DERs that provide this value, mechanism does not compensate for emissions.*				

1. Also eligible for distributor contracts but no data is available for assessment.
2. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

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Managed EV Charging – Gap Identification

Table 2. – cont.

<table>
<tr><th rowspan="3">Managed EV Charging</th><th rowspan="3">Assessment of System Value</th><th colspan="5">Current Compensation Mechanisms[1]</th></tr>
<tr><th colspan="4">Energy Arbitrage</th><th rowspan="2">Hydro One MyRewards</th></tr>
<tr><th>RPP TOU</th><th>RPP ULO</th><th>RPP Tiered</th><th>Non-RPP Class B</th></tr>
<tr><td>Generation capacity</td><td>Value is medium</td><td colspan="3" rowspan="3">For DERs that provide this value, there may be a gap in compensation</td><td>Compensation is lower than value.</td><td rowspan="2">For DERs that provide this value, there may be a gap in compensation</td></tr>
<tr><td>Transmission capacity</td><td rowspan="2">Value is high in regions with Tx/Dx system constraints if charging is shifted away from bulk/local system peak demand periods. Value is zero in regions without constraints.</td></tr>
<tr><td>Distribution capacity</td><td>Participants receive $50 at registration + $5 per month during which the participating device(s) has been called on and responds to curtail electricity demand for at least 50% of scheduled peak demand events</td></tr>
<tr><td>Energy</td><td>Value is low</td><td colspan="2">Compensation is equal to the difference in user costs determined by the change in consumption due to managed charging and the applicable retail rates (for on-peak to off-peak this is approx. 2:1 for TOU and 10:1 for ULO).[2]</td><td>Compensation is lower than value.</td><td>Compensation is equal to the difference in user costs determined by the change in consumption due to managed charging and the applicable wholesale market price.</td><td>For DERs that provide this value, there may be a gap in compensation</td></tr>
<tr><td>Emissions</td><td>Value is low</td><td colspan="5">For DERs that provide this value, there may be a gap in compensation</td></tr>
</table>

1. Also eligible for distributor contracts but no data is available for assessment.
2. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

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BTM Distributed Energy Storage – Current Compensation

Table 2. – cont.

BTM Distributed Energy Storage	Assessment of System Value	Current Compensation Mechanisms[2]				
		Energy Arbitrage		Capacity Auction		Industrial Conservation Initiative
		RPP	Non-RPP Class B	RPP	Class A & Non-RPP Class B	
Generation capacity	*Value is **high.***	*For DERs that provide this value, mechanism does not compensate for generation capacity.[3]*	*Compensation is negative due to losses since the GA rate does not vary by hour.*	*While lower than capacity payments in long-term contracts, the auction clearing price is determined by the bids received for each commitment period. Participants earned approx. $240/MW-business day from May 1, 2023, through April 30, 2025.[3]*		*Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	*For DERs that provide this value, mechanism does not compensate for transmission and distribution capacity.*				
Distribution capacity						
Energy	*Value is **low**.*	*Compensation is equal to the difference in retail rate between charging and discharging, after losses.[3]*	*Compensation is equal to the wholesale market price for avoided energy consumption.*	*Compensation is equal to the retail rate (aggregated RPP resources) or wholesale market price (other resources) for energy injections when participants are dispatched.[3]*		*Compensation is equal to the wholesale market price for avoided energy consumption.*
Emissions	*Value is **low.***	*For DERs that provide this value, mechanism does not compensate for emissions.*				

1. Also eligible for distributor contracts but no data is available for assessment.
2. Participation in the wholesale energy market of aggregated resources is also possible. Compensation under this mechanism would be limited to compensation for energy at the wholesale price.
3. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

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BTM Distributed Energy Storage – Gap Identification

Table 2. – cont.

BTM Distributed Energy Storage	Assessment of System Value	Current Compensation Mechanisms[2]				
		Energy Arbitrage		Capacity Auction		Industrial Conservation Initiative
		RPP	Non-RPP Class B	RPP	Class A & Non-RPP Class B	
Generation capacity	*Value is **high.***	***For DERs that provide this value, there may be a gap in compensation***	***Compensation below value***	*While lower than capacity payments in long-term contracts, the auction clearing price is determined by the bids received for each commitment period. Participants earned approx. $240/MW-business day from May 1, 2023, through April 30, 2025.[3]*		*Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	***For DERs that provide this value, there may be a gap in compensation***				
Distribution capacity						
Energy	*Value is **low**.*	*Compensation is equal to the difference in retail rate between charging and discharging, after losses.[3]*	*Compensation is equal to the wholesale market price for avoided energy consumption.*	*Compensation is equal to the retail rate (aggregated RPP resources) or wholesale market price (other resources) for energy injections when participants are dispatched.[3]*		*Compensation is equal to the wholesale market price for avoided energy consumption.*
Emissions	*Value is **low.***	***For DERs that provide this value, there may be a gap in compensation***				

1. Also eligible for distributor contracts but no data is available for assessment.
2. Participation in the wholesale energy market of aggregated resources is also possible. Compensation under this mechanism would be limited to compensation for energy at the wholesale price.
3. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

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BTM Distributed Generation – Current Compensation

Table 2. – cont.

BTM Distributed Generation	Assessment of System Value	Current Compensation Mechanisms[1,2]				
		eDSM Framework		Net Metering		Industrial Conservation Initiative
		RPP	Non-RPP Class B	RPP	Non-RPP Class B	
Generation capacity	*Value is **medium.***	*Compensation includes an upfront incentive of $860-$1000/kW for up to 50% of solar PV system costs.[3]*		*For DERs that provide this value, mechanism does not compensate for generation capacity.[3]*		*Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.*
Transmission capacity	*Value is **medium** in regions with Tx/Dx system constraints due to lower UCAP values and limited generation during peak demand periods. **Value is zero in regions without constraints.***	*For DERs that provide this value, mechanism does not compensate for transmission and distribution capacity.*				
Distribution capacity						
Energy	*Value is **medium.***	*Compensation is equal to the retail rate for avoided energy consumption.[3]*		*Compensation is equal to the applicable retail rate for avoided & injected energy (via bill credits).[3]*		*Compensation is equal to the wholesale market price for avoided energy consumption.*
Emissions	*Value is **medium.***	*No direct compensation for avoided emissions but participation is limited to solar PV (eDSM) or renewable generation (net metering). As such any compensation is limited to non-emitting resources.*				*For DERs that provide this value, mechanism does not compensate for emissions.*

1. Also eligible for distributor contracts but no data is available for assessment.
2. Participation in the wholesale energy market of aggregated resources is also possible. Compensation under this mechanism would be limited to compensation for energy at the wholesale price.
3. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

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BTM Distributed Generation – Gap Identification

Table 2. – cont.

BTM Distributed Generation	Assessment of System Value	Current Compensation Mechanisms[1,2]				
		eDSM Framework		Net Metering		Industrial Conservation Initiative
		RPP	Non-RPP Class B	RPP	Non-RPP Class B	
Generation capacity	*Value is **medium.***	*Compensation includes an upfront incentive of $860-$1000/kW for up to 50% of solar PV system costs.[3]*		***Compensation is zero. May not represent a gap if compensation for energy exceeds value.***		*Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.*
Transmission capacity	*Value is **medium** in regions with Tx/Dx system constraints due to lower UCAP values and limited generation during peak demand periods. **Value is zero in regions without constraints.***	***For DERs that provide this value, there may be a gap in compensation***				
Distribution capacity						
Energy	*Value is **medium.***	*Compensation is equal to the retail rate for avoided energy consumption.[3]*		***Compensation may exceed value as retail rates includes costs beyond generation***		*Compensation is equal to the wholesale market price for avoided energy consumption.*
Emissions	*Value is **medium.***	***For DERs that provide this value, there may be a gap in compensation***				

1. Also eligible for distributor contracts but no data is available for assessment.
2. Participation in the wholesale energy market of aggregated resources is also possible. Compensation under this mechanism would be limited to compensation for energy at the wholesale price.
3. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

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BTM Hybrid – Current Compensation

Table 2. – cont.

BTM Hybrid	Assessment of System Value	Current Compensation Mechanisms[1,2]				
		eDSM Framework		Net Metering		Industrial Conservation Initiative
		RPP	Non-RPP Class B	RPP	Non-RPP Class B	
Generation capacity	*Value is **high***	*Compensation is equal to the upfront incentive of $860-$1000/kW for up to 50% of solar PV system costs (plus $300/kWh incentive for pairing a battery for residential systems only).[3]*		*For DERs that provide this value, mechanism does not compensate for generation capacity.[3]*		*Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	*For DERs that provide this value, mechanism does not compensate for transmission and distribution capacity.*				
Distribution capacity						
Energy	*Value is **medium***	*Compensation is equal to the retail rate for avoided energy consumption.[3]*	*Compensation is equal to the wholesale market price for avoided energy consumption.*	*Compensation is equal to the applicable retail rate for avoided & injected energy (via bill credits).[3]*		*Compensation is equal to the wholesale market price for avoided energy consumption.*
Emissions	*Value is **medium***	*No direct compensation for avoided emissions but participation is limited to solar PV (eDSM) or renewable generation (net metering). As such compensation is only available to non-emitting resources.*				*Mechanism does not compensate for emissions.*

1. Also eligible for distributor contracts but no data is available for assessment.
2. Participation in the wholesale energy market of aggregated resources is also possible. Compensation under this mechanism would be limited to compensation for energy at the wholesale price.
3. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

BTM Hybrid – Gap Identification

Table 2. – cont.

BTM Hybrid	Assessment of System Value	Current Compensation Mechanisms[1,2]				
		eDSM Framework		Net Metering		Industrial Conservation Initiative
		RPP	Non-RPP Class B	RPP	Non-RPP Class B	
Generation capacity	*Value is **high***	*Compensation is equal to the upfront incentive of $860-$1000/kW for up to 50% of solar PV system costs (plus $300/kWh incentive for pairing a battery for residential systems only).[3]*		***For DERs that provide this value, there may be a gap in compensation***		*Compensated via reduced consumption in top 5 demand hours by proportional reduction to GA charges.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	***For DERs that provide this value, there may be a gap in compensation***				
Distribution capacity						
Energy	*Value is **medium***	*Compensation is equal to the retail rate for avoided energy consumption.[3]*	*Compensation is equal to the wholesale market price for avoided energy consumption.*	*Compensation is equal to the applicable retail rate for avoided & injected energy (via bill credits).[3]*		*Compensation is equal to the wholesale market price for avoided energy consumption.*
Emissions	*Value is **medium***	***For DERs that provide this value, there may be a gap in compensation***				

1. Also eligible for distributor contracts but no data is available for assessment.
2. Participation in the wholesale energy market of aggregated resources is also possible. Compensation under this mechanism would be limited to compensation for energy at the wholesale price.
3. RPP retail rates recover wholesale market and out-of-market (Global Adjustment) energy supply costs. While a subset of Global Adjustment costs are better attributed to generation capacity, for clarity, total compensation via RPP retail rates is attributed to the energy component of the value stack.

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FTM Distributed Generation – Current Compensation

Table 2. – cont.

FTM Distributed Generation	Assessment of System Value	Current Compensation Mechanisms[1,2,3]
		Wholesale energy market
Generation capacity	*Value is **medium***	*For DERs that provide this value, mechanism does not compensate for generation, transmission and distribution capacity.*
Transmission capacity	*Value is **medium** in regions with Tx/Dx system constraints due to lower UCAP values and limited generation during peak demand periods. **Value is zero in regions without constraints.***	
Distribution capacity		
Energy	*Value is **medium***	*Compensation is equal to the wholesale market price for injected electricity*
Emissions	*Value is **medium***	*For DERs that provide this value, mechanism does not compensate for emissions.*

1. IESO is aiming to enable variable generation resources to qualify for participation in the capacity auction.
2. Also eligible for LT2e with restrictions, no data available as procurement is not complete
3. Also eligible for distributor contracts but no data is available for assessment.

FTM Distributed Generation – Gap Identification

Table 2. – cont.

FTM Distributed Generation	Assessment of System Value	Current Compensation Mechanisms[1,2,3]
		Wholesale energy market
Generation capacity	*Value is **medium***	***For DERs that provide this value, there may be a gap in compensation***
Transmission capacity	*Value is **medium** in regions with Tx/Dx system constraints due to lower UCAP values and limited generation during peak demand periods. **Value is zero in regions without constraints.***	
Distribution capacity		
Energy	*Value is **medium***	*Compensation is equal to the wholesale market price for injected electricity*
Emissions	*Value is **medium***	***For DERs that provide this value, there may be a gap in compensation***

1. IESO is aiming to enable variable generation resources to qualify for participation in the capacity auction.
2. Also eligible for LT2e with restrictions, no data available as procurement is not complete
3. Also eligible for distributor contracts but no data is available for assessment.

FTM DES – Current Compensation

Table 2. – cont.

FTM Distributed Energy Storage	Assessment of System Value	Current Compensation Mechanisms[1,2]		
		Wholesale energy market	**Capacity Auction**	**Long-term procurement contracts**
Generation capacity	*Value is **high***	*DES pay the Class B GA rate for electricity to charge and receive GA credits for electricity discharged.*	*While lower than capacity payments in long-term contracts, the auction clearing price is determined by the bids received for each commitment period. Participants earned approx. $240/MW-business day from May 1, 2023, through April 30, 2025.*	*Compensation is equal to system value due to competitive procurement. Resources awarded long-term contracts are guaranteed a fixed payment for capacity. The recent e-LT1 procurement round resulted in a weighted avg. payment of $881/MW-business day.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	*For DERs that provide this value, mechanism does not compensate for transmission and distribution capacity.*		
Distribution capacity				
Energy	*Value is **low***	*Compensation is equal to the difference in wholesale market price between charging and discharging, after losses.*	*When participants are dispatched, compensation is equal to the difference in wholesale market price between charging and discharging, after losses.*	*Compensation is equal to the difference in wholesale market price between charging and discharging, after losses.*
Emissions	*Value is **low***	*For DERs that provide this value, mechanism does not compensate for emissions.*		

1. Also eligible for distributor contracts but no data is available for assessment.
2. Compensation via energy arbitrage would be equivalent to compensation through the wholesale market with the exception that market participant DES would be compensated via their Locational Marginal Price and non-market participants would be compensated via the Ontario Zonal Price plus Load Forecast Deviation Adjustment.

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FTM DES – Gap Identification

Table 2. – cont.

FTM Distributed Energy Storage	Assessment of System Value	Current Compensation Mechanisms[1,2]		
		Wholesale energy market	**Capacity Auction**	**Long-term procurement contracts**
Generation capacity	*Value is **high***	***Current compensation is inversely related to system value.***	*While lower than capacity payments in long-term contracts, the auction clearing price is determined by the bids received for each commitment period. Participants earned approx. $240/MW-business day from May 01, 2023, through Apr 30, 2025.*	*Compensation is equal to system value due to competitive procurement. Resources awarded long-term contracts are guaranteed a fixed payment for capacity. The recent e-LT1 procurement round resulted in a weighted avg. payment of $881/MW-business day.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	***For DERs that provide this value, there may be a gap in compensation***		
Distribution capacity				
Energy	*Value is **low***	*Compensation is equal to the difference in wholesale market price between charging and discharging, after losses.*	*When participants are dispatched, compensation is equal to the difference in wholesale market price between charging and discharging, after losses.*	*Compensation is equal to the difference in wholesale market price between charging and discharging, after losses.*
Emissions	*Value is **low***	***For DERs that provide this value, there may be a gap in compensation***		

1. Also eligible for distributor contracts but no data is available for assessment.
2. Compensation via energy arbitrage would be equivalent to compensation through the wholesale market with the exception that market participant DES would be compensated via their Locational Marginal Price and non-market participants would be compensated via the Ontario Zonal Price plus Load Forecast Deviation Adjustment.

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FTM Hybrid – Current Compensation

Table 2. – cont.

FTM Hybrid	Assessment of System Value	Current Compensation Mechanisms[1,2,3,4]
		Wholesale energy market
Generation capacity	*Value is **high***	*For DERs that provide this value, mechanism does not compensate for generation, transmission, and distribution capacity.*
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	
Distribution capacity		
Energy	*Value is **medium***	*Compensation is equal to the wholesale market price for energy consumption and injection when dispatched.*
Emissions	*Value is **medium***	*For DERs that provide this value, mechanism does not compensate for emissions.*

1. IESO is aiming to enable variable generation resources to qualify for participation in the capacity auction.
2. Also eligible for LT1, LT2e, LT2c with restrictions, no data available as procurement is not complete
3. Also eligible for distributor contracts but no data is available for assessment.
4. Compensation via energy arbitrage would be equivalent to compensation through the wholesale market with the exception that market participants would be compensated via their Locational Marginal Price and non-market participants would be compensated via the Ontario Zonal Price plus Load Forecast Deviation Adjustment.

FTM Hybrid – Gap Identification

Table 2. – cont.

FTM Hybrid	Assessment of System Value	Current Compensation Mechanisms[1,2,3,4]
		Wholesale energy market
Generation capacity	*Value is **high***	***For DERs that provide this value, there may be a gap in compensation***
Transmission capacity	*Value is **high** in regions with Tx/Dx system constraints due to resource's high UCAP and availability during bulk/local peak demand hours. **Value is zero in regions without constraints.***	
Distribution capacity		
Energy	*Value is **medium***	*Compensation is equal to the wholesale market price for energy consumption and injection when dispatched.*
Emissions	*Value is **medium***	***For DERs that provide this value, there may be a gap in compensation***

1. IESO is aiming to enable variable generation resources to qualify for participation in the capacity auction.
2. Also eligible for LT1, LT2e, LT2c with restrictions, no data available as procurement is not complete
3. Also eligible for distributor contracts but no data is available for assessment.
4. Compensation via energy arbitrage would be equivalent to compensation through the wholesale market with the exception that market participants would be compensated via their Locational Marginal Price and non-market participants would be compensated via the Ontario Zonal Price plus Load Forecast Deviation Adjustment.

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Part 1: DER Compensation

Jurisdictional Scan

Jurisdictional Scan of DER Compensation

The OEB reviewed four jurisdictions to understand how DERs are compensated in each. The jurisdictions were chosen based on levels of DER integration, DER policy goals and regulatory reforms related to DER compensation. Table 3 summarizes DER policies and compensation mechanisms in each jurisdiction.

Table 3. Overview of compensation mechanism types across four jurisdictions

	New York State	Hawaii	Australia	California
	New York State has set a 2040 mandate to achieve 100% zero-emissions electricity. The State exceeded its goal of 6 GW of distributed solar by 2025 and is targeting 10 GW by 2030. More than 1,500 small-scale (<1 MW) solar and battery storage projects are operational statewide.	Hawaii has a 100% renewable electricity goal by 2045. Hawaii has achieved a 36.7% renewable portfolio in Hawaiian Electric's territory and 57.9% in Kauai Co-op territory. Nearly half of this comes from rooftop solar, with 96% of residential systems now paired with energy storage.	Australia leads globally in rooftop solar per capita, with over 26.8 GW installed capacity. Electricity generated from rooftop solar accounted for 12.8% of Australia's total electricity generation in the first half of 2025.	California has 17.4 GW of installed BTM solar PV, which has displaced approximately 10% of energy supplied by local utilities. In 2024, statewide battery energy storage capacity reached 15 GW across all sectors, with distributed energy storage accounting for 2,515 MW.
	Summary of DER Compensation Mechanisms			
Price-based mechanisms	• Shift from net metering to Value of DER (VDER) Tariff • Time-of-use (TOU) tariffs including time varying demand charge pilot	• Shift from net metering to Smart Rate • Shift and Save TOU paired with Smart Rates	• Shift from gross Feed-in-Tariffs (FiTs) to dynamic FiTs • Controllable load and demand charge tariffs	• Shift from net metering to Net Billing Tariffs (NBTs) • Virtual & Community Net Metering • Other targeted TOUs
Procurement and wholesale market mechanisms	• DER Aggregation Framework • New York Independent System Operator-administered DR programs for grid services	• Market participation not available due to absence of a wholesale market • Grid Service Purchase Agreement via aggregators	• DER Orchestration Framework • Fast Frequency Response • Aggregated DERs and virtual power plants • Wholesale market demand response	• DER Aggregation Model enables participation in energy & ancillary services markets • Reliability and proxy demand response
Program-based mechanisms	• Peak demand and emergency load reduction • Community solar • Upfront cost incentives for solar and battery	• Fast Demand Response • Community solar • Upfront cost incentives for batteries	• Pilot programs reward residential customers for reducing electricity use during peak demand or grid stress events • Solar and battery rebates	• Demand response including critical peak pricing and capacity bidding for incentives or bill discounts • Incentives for installing generation and storage technologies

Jurisdictional Scan – New York

A summary of New York State's energy profile, policy goals and major DER reforms is provided in Figure 1. An overview of DER compensation mechanisms by type is provided in the following pages.

Figure 1. Summary of New York's Electricity System and Overarching Policies

Policy Goal[1]	Electricity System Overview
• **70%** renewable energy by 2030 • **100%** of new passenger cars, SUVs, and pickup trucks sold in the state must be zero-emission by 2035 • **100%** zero-emissions electricity by 2040 • **85%** reduction in greenhouse gas (GHG) emissions by 2050	• The Federal Energy Regulatory Commission (FERC) regulates interstate transmission and oversees New York Independent System Operator tariffs. • The New York Independent System Operator manages wholesale electricity markets and ensures grid reliability. • The New York Public Service Commission sets retail rates and monitors utility service quality. • Utilities like Con Edison and National Grid handle electricity distribution and customer service. • Energy Service Companies offer competitive supply options, often focused on renewables.

Fuel Mix (2024)[2]

Major DER Reforms

- **New York transitioned from net metering to the VDER tariff**[3] to provide a more precise price signal for DER products and services and to offer fair and accurate compensation for the value they create. 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.
- **FERC Order 2222**, a landmark directive, enforced reforms around how DERs participate in the wholesale market, leading to DER Aggregation Framework adoption.

Energy Sector Facts[4,5,6,7,8]

40.8 GW
Total Installed Capacity

124.5 TWh
Total Generation

7.2 GW
Rooftop Solar Capacity

509.2 MW
Battery Storage Capacity

~131,250
Electric Vehicles

1. New York Independent System Operator. 2025. *Power Trends: The New York ISO Annual Grid and Markets Report*
2. US Energy Information Administration. *Electricity Data Browser*. Fuel mix total may not add to 100% due to rounding.
3. State of New York Public Service Commission. March 9, 2017. *Order on Net Metering Transition, Phase One Value of DERs, and Related Matters*
4. U.S. Energy Information Administration. August 2024. *Table 6.2. A. Net Summer Capacity of Utility Scale Units by Technology and State*.
5. New York Independent System Operator. 2024. *2024 Power Trends: the New York ISO Annual Grid and Markets Report*.
6. New York State Energy Research and Development Authority. *April 30, 2024*. *Statewide Distributed Solar Projects*.
7. New York State Department of Public Service. April 1, 2024. *State of Storage in New York.*
8. U.S. Department of Energy, Alternative Fuels Data Center. September 2024. *Electric Vehicle Registrations by State*.

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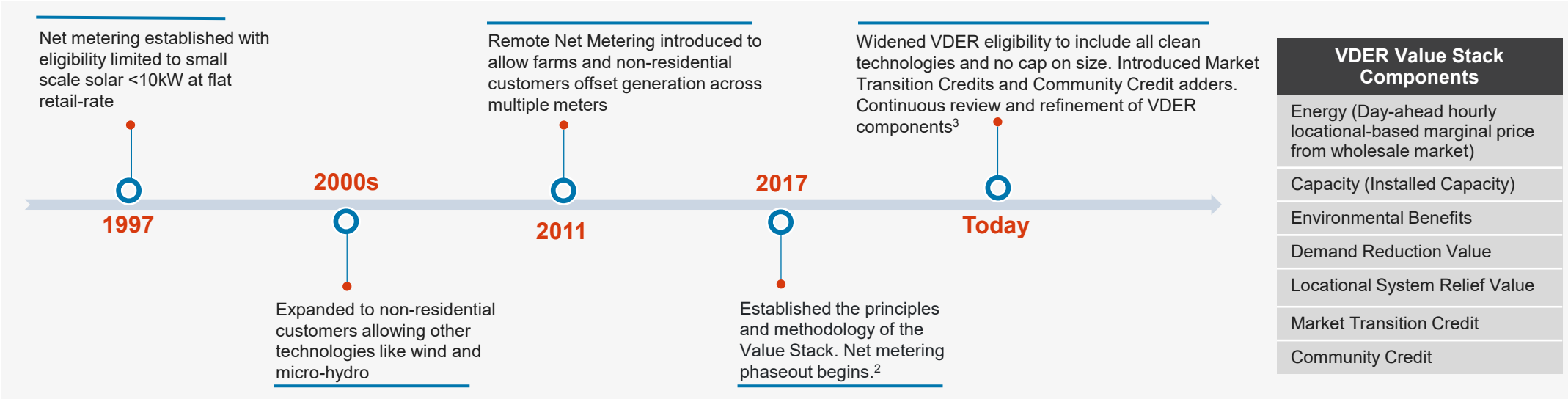
Jurisdictional Scan – New York

Table 4 provides an overview of price-based compensation mechanisms in New York. As of 2017, New York has transitioned from net metering to a VDER tariff, shifting from time-invariant retail-rate compensation to a more dynamic, location- and time-based rate[1]. Figure 2 shows the evolution of net metering and introduces the various value stack components of the VDER tariff.

Table 4. Overview of price-based compensation mechanisms in New York State

Price-based Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
Smart Energy Plan	Con Edison's pilot program with time-varying demand charges for distribution service.	All DER types, Smart Meter mandatory
VDER	Compensates for exported energy based on value stack components.	Mostly technology neutral but depends on the value stack component

Figure 2. Evolution of net metering in New York



1. State of New York Public Service Commission. March 9, 2017. *Order on Net Metering Transition, Phase One Value of DERs, and Related Matters*
2. *NYSERDA*. June 12, 2020. *Value Stack Fact Sheet.*
3. State of New York Public Service Commission. September 12, 2018. *Order on Value Stack Eligibility Expansion and Other Matters*.

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Jurisdictional Scan – New York

Table 5 provides an overview of procurement and wholesale market compensations mechanisms available in New York. These mechanisms offer compensation for grid services such as peak load reduction, emergency support and market-based flexibility. DERs currently enrolled in the VDER tariff may also be eligible to participate. Program structures and eligibility vary, and some restrictions may apply based on operational models or market roles. Table 5 outlines these mechanisms which are either utility-led or New York Independent System Operator-led and are currently available to DERs.

Table 5. Overview of procurement and wholesale market compensation mechanisms in New York State

Procurement and Wholesale Market Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
Emergency Demand Response Program[1]	Voluntary DR with compensation tied to wholesale prices.	Flexible loads, on-site generation
Installed Capacity Special Case Resource[1]	Mandatory DR with capacity and energy payments.	Flexible loads, on-site generation
Day-Ahead Demand Response Program[2]	Allows curtailment bids into the Day-Ahead Market.	Flexible loads
Demand-Side Ancillary Services Program[3]	Enables DERs to provide reserves and regulation services.	Flexible loads, advanced battery storage
DER Aggregation Participation Model[4]	Allows small DERs to aggregate and participate in markets.	• Solar, storage, DR, mixed DERs ≥10 kW • BTM non-generating resource must routinely serve its host load by withdrawing from the grid to be eligible

1. New York Independent System Operator. *Demand Response Programs*.
2. New York Independent System Operator. July 2024. *NYISO Day-Ahead Demand Response Program Manual.*
3. New York Independent System Operator. April 29, 2008. *Demand-Side Ancillary Service Program*.
4. New York Independent System Operator. Distributed Energy Resource and Aggregation Participation Model.

Jurisdictional Scan – New York

Table 6 provides an overview of program-based compensation mechanisms in New York. These compensations include programmatic incentives for solar installations and battery storage, including upfront payments, subscription-based credit programs, performance-based compensation and long-term revenue mechanisms for larger projects. These programs are generally open to various DER types, but restrictions on dual participation do exist depending on the specific incentive and program structure.

Table 6. Overview of program-based compensation mechanisms in New York State

Program-based Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
NY-SUN Initiative[1]	Provides upfront incentives for solar, plus $350/kWh bonus for paired storage.	Solar PV, solar + battery
Community Solar Program[2]	Enables subscription to shared solar projects with bill credits.	Solar (shared systems)
Retail Energy Storage Incentive[3]	Funds battery systems up to 5 MW for peak shaving and DR participation.	Battery storage (<5 MW)
Bulk Energy Storage Program[4]	Supports large-scale storage with long-term revenue via Index Credits and encourages participation in the wholesale energy and capacity markets.	Battery storage (>5 MW)
Commercial System Relief Program[5]	Pays for load reduction during peak periods.	Commercial and industrial flexible loads and battery storage
Distribution Load Relief Program[6]	Pays for emergency load reduction to support grid reliability.	Commercial and industrial flexible loads and battery storage
New York City Department of Citywide Administrative Services Demand Response Program[7]	Municipal DR initiative that generates revenue for municipal agencies for reducing peak load.	Flexible loads in municipal agencies

1. NYSERDA. *NY-SUN Solar Program*.
2. NYSERDA. Community Solar Program.
3. NYSERDA. *Residential and Retail Storage Incentives*.
4. NYSERDA. *Bulk Energy Storage Program.*
5. NYSEG. *Commercial System Relief Program*.
6. New York Independent System Operator. *Distribution Load Relief Program*.
7. New York Department of Citywide Administrative Services. Demand Response Program.

Jurisdictional Scan – New York

A summary of the findings from the jurisdictional scan of New York State is provided below.

Summary of DER Compensation in New York State

New York has exceeded its 6 GW distributed solar target ahead of the 2025 deadline and now aims for 10 GW by 2030, supported by over 1,500 small-scale solar and battery storage projects under 1 MW and approximately 400 MW of deployed battery capacity.[1]

While TOU rates and rebate programs in New York are broadly comparable to those available in Ontario, New York shifted from net metering to the VDER tariff in 2017 to provide more precise price signals for DER products and services. The commission found that net metering "…has little or no relationship to the actual values provided to or costs imposed on the system" and "In order to incentivize customers and DER providers to install and operate DER in a manner that maximizes the benefits for themselves, the integrated electric system, and society as a whole, compensation must accurately reflect the values created at a granular level." The VDER tariff is a time and location-varying rate that applies to electricity injected into the distribution system.[2]

New York has integrated DERs into the wholesale energy market via the Aggregation Model[3]. Under this framework, dispatchable DERs can elect to provide Energy, Ancillary Services and Capacity in real time through aggregated participation.

In addition, FERC Order No. 2222 serves as a timely complement to New York's DER Aggregation Participation Model, enabling multiple DERs with a minimum aggregated capacity of 100 kW to participate in energy markets and grid services under a unified framework. This alignment reinforces New York's broader commitment to full DER integration and grid modernization.

1. NYSERDA. October 17, 2024. *New York State Has Achieved Major Solar Milestone A Year Early*.
2. State of New York Public Service Commission. March 9, 2017. *Order on Net Metering Transition, Phase One Value of DERs, and Related Matters.*
3. New York Independent System Operator. *Distributed Energy Resources Participation Model*.

Jurisdictional Scan – Hawaii

Figure 3. Summary of Hawaii's Electricity System and Overarching Policies

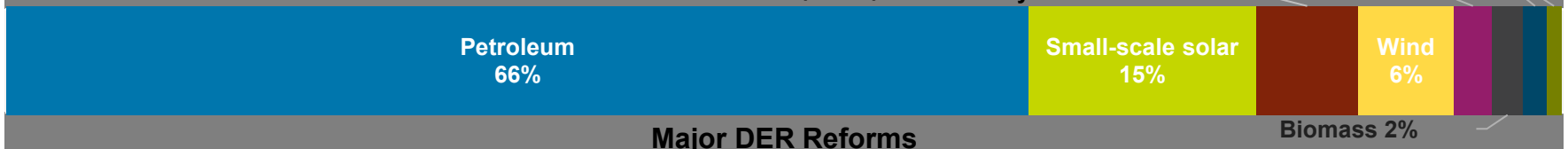
Policy Goal

- **50%** reduction in GHG emissions below 2005 levels by 2030.[1]
- **50,000** distributed renewable energy installations b 2030.[2]
- **100%** Clean Transportation by 2045.[3]
- **Net-Negative** Emissions by 2045.[4]

Electricity System Overview

- Hawaii Public Utilities Commission regulates electricity rates and utility operations across the state.
- Hawaii's electricity system is served by four regulated, vertically integrated utilities, three of which operate under Hawaiian Electric.
- Hawaiian Electric serves approximately 95% of Hawaii's population across O'ahu, Maui, Hawai'i and Lanai and Molokai Island.
- Hawaii's electricity system does not operate in a competitive wholesale market and does not have an independent system operator. As a result, the FERC plays a limited role in this jurisdiction.

Fuel Mix (2024)[5]



Major DER Reforms

- **Hawaii phased out net metering** in 2015, citing grid reliability and cost equity concerns and transitioned to Smart Export Rates. While there's no formal value stacking framework, customers are permitted to layer benefits where feasible by participating in multiple programs simultaneously.
- **In 2024, Act 266 authorized energy wheeling** for state and county facilities and directed the Public Utilities Commission to establish tariffs for grid services, microgrids and wheeling by 2027.[6]

Energy Sector Facts[7,8,9,10,11]

3.2 GW
Total Installed Capacity

9.1 TWh
Total Generation

1.26 GW
Rooftop Solar Capacity

~4,800
Customer Battery Installations

~39,100
Electric Vehicles

1. Legislature of the State of Hawaii. July 5, 2022. *Act 238: A Bill for an Act Relating to Climate Mitigation.*
2. Hawaii State Energy Office. January 27, 2025. *Executive Order No. 25-01: Accelerating Hawai'i's Transition Toward 100 Percent Renewable Energy*
3. Hawaii State Energy Office. *Hawaii Clean Energy Initiative*
4. 2024. *225P-5: Zero emissions clean economy target*
5. US Energy Information Administration. *Electricity Data Browser*. Fuel mix total may not add to 100% due to rounding.
6. According to Act 266, "retail wheeling" means the transmission of electric power from a storage or energy generation system through the utility meter for consumption by a separate utility account holder." January 17, 2025. *Hawaii House Bill 790*
7. U.S. Energy Information Administration. April 2024. *Table 6.2. A. Net Summer Capacity of Utility Scale Units by Technology and State.*
8. U.S. Energy Information Administration. 2024. *Net generation for all sectors, annual.*
9. Hawaiian Electric. March 31, 2024. *Cumulative Installed PV*.
10. Hawaii Department of Business, Economic Development & Tourism. May 2023. *Solar PV Battery Installations in Honolulu 2022 Update.*
11. Hawaii Department of Business, Economic Development & Tourism. September 2025. *Monthly Energy Trends.*

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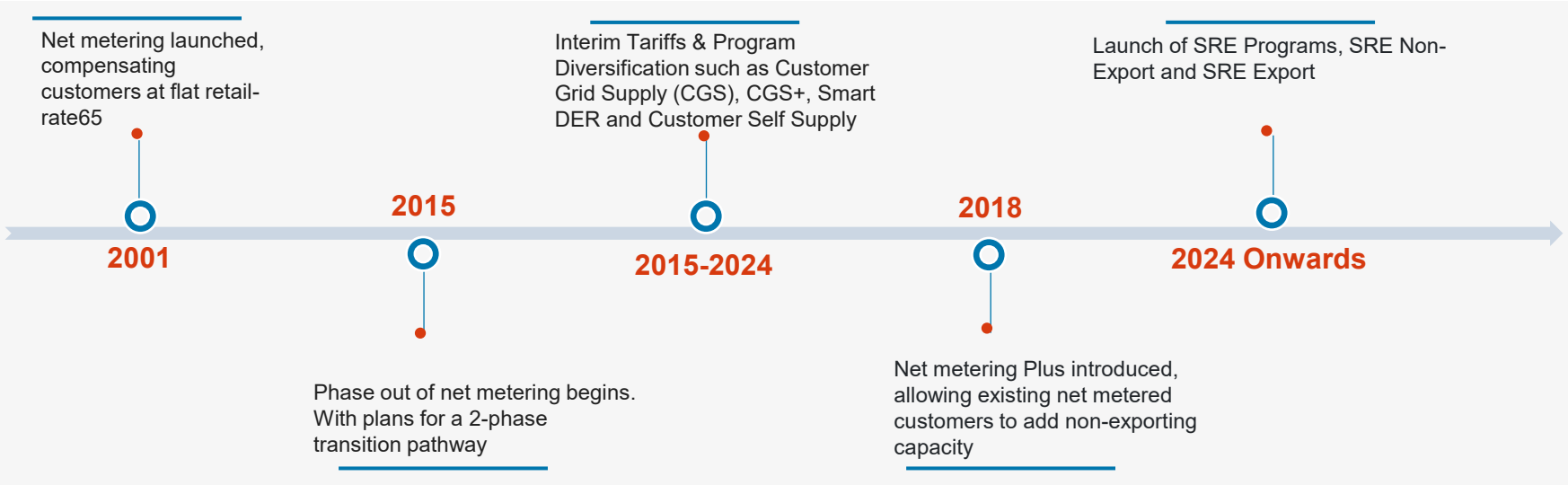
Jurisdictional Scan – Hawaii

Table 7 provides an overview of price-based compensation mechanism in Hawaii. In 2015, Hawaii phased out net metering and, as of 2024, introduced Smart Renewable Energy (SRE) Rates, as shown in Figure 4. Additionally, Hawaiian Electric offers a TOU rate program called "Shift and Save," into which all SRE customers are automatically enrolled. Non-SRE customers can also enroll into 'Shift and Save."

Table 7. Overview of price-based compensation mechanisms in Hawaii

Price-based Mechanisms		
Mechanism	**Description**	**Eligible DER Types**
Shift and Save[1]	A TOU tariff to incentivize shifting energy use to off-peak hours	Technology neutral
Smart Renewable Energy Export[2]	Time-varying bill credits for exported energy	All renewable technology
Smart Renewable Energy Non-Export[3]	Supports self-consumption, no export allowed	Technology neutral

Figure 4 Evolution of net metering in Hawaii[4]



1. Hawaiian Electric. *Shift and Save*.
2. Hawaiian Electric. *Smart Renewable Energy Export.*
3. Hawaiian Electric. Smart Renewable Energy Non-Export. .
4. Lawrence Berkeley National Laboratory, July 24, 2019. *Current Developments in Retail Rate Design: Implications for Solar and Other Distributed Energy Resources*

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Jurisdictional Scan – Hawaii

Table 8 provides an overview of procurement-based compensation mechanisms in Hawaii. Due to the absence of a wholesale electricity market, market-based compensation mechanisms for DERs do not exist in Hawaii. There is currently one procurement-based mechanism, as shown in Table 8, that allows DER aggregators to enroll customer devices under Grid Services Purchase Agreements to deliver fast frequency response and capacity services.

Table 8. Overview of procurement and market-based compensation mechanisms in Hawaii

Procurement and Wholesale Market Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
Power Partners[1]	Grid Services Purchase Agreements with aggregators to deliver services like fast frequency response, capacity build and capacity reduction.	Aggregated DERs

Under its program-based mechanisms, Hawaii compensates through various forms such as upfront incentives for batteries and bill credits for community solar, as well as demand response programs as shown in Table 9.

Table 9. Overview of market-based compensation mechanisms in Hawaii

Program-based Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
Bring Your Own Device Plus[2]	Upfront incentives and retail-rate export credits for battery dispatch during peak hours	Battery energy storage systems
Shared Solar[3]	Subscribe to community solar projects and receive monthly bill credits	Community solar
Fast Demand Response[4]	For commercial/industrial customers offering bill credits for peak period load reduction	C&I flexible loads

1. Hawaiian Electric. *Power Partnership Programs*.
2. Hawaiian Electric. *Bring Your Own Device Plus.*
3. Hawaiian Electric. *Shared Solar*.
4. Hawaiian Electric. *Fast Demand Response*.

Jurisdictional Scan – Hawaii

A summary of the findings from the jurisdictional scan of Hawaii is provided below.

Summary of DER Compensation in Hawaii

Due to the absence of a wholesale electricity market, DER compensation in Hawaii mainly consists of program- and price-based mechanisms. After distributed solar capacity rose to approximately 12% of total generation[1], Hawaii replaced net metering with a series of successive DER tariffs in 2015. This shift was driven by grid reliability concerns, cost equity, 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 SRE rates, available today, require customers to install advanced meters and automatically enroll in the Shift and Save time-of-use rate, which incentivizes shifting energy consumption to off-peak hours. This has increased the number of battery systems paired with customer-cited generation, with 96% of residential systems now paired with energy storage.

As of 2024, customer-sited solar contributes approximately 18%[2] of the state's renewable fuel mix, which accounts for nearly half of total renewable generation, perhaps driven by adoption policies, targeted incentives, and declining solar technology costs. Furthermore, recent legislation authorizes energy wheeling for state facilities and directs the Public Utilities Commission to establish tariffs for grid services, microgrids, and wheeling by 2027. These statutory mandates may lead to market-based compensation mechanisms and expanded DER integration, positioning Hawaii to further advance its energy goals under the 100% Renewable Portfolio Standard.

1. 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*)
2. Hawaiian Electric. *2024-2025 Sustainability Report & Maps*

Jurisdictional Scan – Australia

Figure 5. Summary of Australia's Electricity System and Overarching Policies

Policy Goal	Electricity System Overview
• **82%** renewable electricity by 2030[1] • **62–70%** below 2005 levels by 2035, to achieve **net zero** emissions by 2050.[1]	• Australia's electricity system is governed by Australian Energy Market Operator (operations), Australian Energy Market Comission (market rules), and Australian Energy Regulator (regulation), working together to oversee the national energy framework. • These entities support the National Electricity Market, enabling wholesale electricity trading across five states. Western Australia and the Northern Territory are not part of the National Electricity Market and operate under separate regulatory frameworks • Each state maintains its own transmission and distribution networks and retailers serve consumers directly.

2024 Fuel Mix[2]

Major DER Reforms

- **Australia's evolution of FiTs**, where FiT rates became lower, retailer-set and increasingly dynamic, rewarding only surplus electricity exported to the grid.
- Over the last few years, **Australia's consideration of DER orchestration** emerged with Energy Policy Western Australia's DER Roadmap and was advanced through VPP trials and DER integration frameworks.

Energy Sector Facts[3,4,5,6]

- **77.6 GW** Total Installed Capacity
- **185 TWh** Total Generation
- **26.8 GW** Rooftop Solar Capacity
- **54,156** Solar Battery Systems
- **~130,000** EVs

1. Australian Government, Department of Climate Change, Energy, the Environment and Water, September 18, 2025. *Setting our 2035 target and path to net zero*.
2. Australian Government, Department of Climate Change, Energy, the Environment and Water, August 22, 2025. *Australian Energy Update 2025 | energy.gov.au*.
3. Australian Energy Regulator. *State of the Energy Market 2023*.
4. Clean Energy Council, July – December 204. Rooftop solar and storage report.
5. Clean Energy Regulator. *Small-scale installation postcode data as of 2025*.
6. Electric Vehicle Council, July 2023. *State of Electric Vehicles*.

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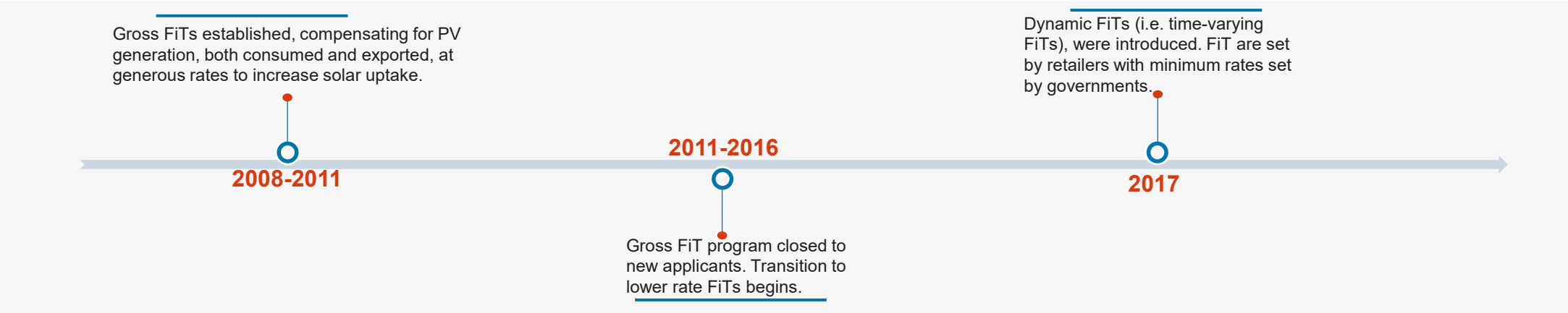
Jurisdictional Scan – Australia

Table 10 provides an overview of price-based compensation mechanisms in Australia. This includes mechanisms that compensate for reducing peak-hour usage or penalize peak power spikes, incentivize off-peak smart appliance operation and offer variable FiTs that reward electricity exports based on dynamic pricing. Gross FiTs were phased out in 2011 and replaced with the current net FiT structure offered in Australia, as illustrated in Figure 6.

Table 10. Overview of price-based compensation mechanisms in Australia

Price-based Mechanisms[1]		
Mechanism	**Description**	**Eligible DER Type**
TOU Tariffs	Incentivizes shifting energy use to off-peak hours through variable pricing based on time, day and season	Technology Neutral
Variable FiTs	Offers time-varying or block-structured credits for exported solar energy.	Solar PV, Hybrid
Controlled Load Tariffs	Applies to specific appliances (e.g., electric hot water systems) operating during off-peak hours via separate metering.	Smart appliances
Demand Charge Tariffs	Adds fees based on peak power usage. Avoiding large spikes will reduce electricity bill.	Technology Neutral

Figure 6. Evolution of FiTs in Australia[1]



1. Australian Government, Department of Climate Change, Energy, the Environment and Water, n.d. *Electricity pricing plans and tariffs.*
2. Australian Energy Regulator, 2017. *AER factsheet - Victoria - How to get value for your renewable energy and feed-in tariffs explained | Australian Energy Regulator (AER)*.

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Jurisdictional Scan – Australia

Table 11 provides an overview of procurement and market-based compensation mechanisms in Australia. While some mechanisms remain in pilot stages or focus on standard solar and battery rebates, others have matured into established pathways for DER market participation through aggregators and VPPs.

Table 11. Overview of procurement and market-based compensation mechanisms in Australia

Procurement and Wholesale Market Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
Wholesale Demand Response Mechanism[1]	Allows large energy users to bid on demand reductions directly into the National Electricity Market.	Commercial & industrial flexible loads
Project Jupiter/Project Symphony[2]	Aggregates residential and community energy assets into VPPs for market participation	Solar PV, battery storage, community energy assets
Amber Electric SmartShift[3]	Automates battery charging/discharging based on real-time wholesale prices	Battery storage
Discover Energy VPP[4]	Participants earn fixed export rates and profit share from wholesale market trading for exporting during VPP events	Solar PV, Battery storage
Frequency Control Ancillary Services	DERs provide frequency regulation and contingency services, earning revenue for fast-response capabilities	Battery storage, flexible loads

1. Australia Energy Market Operator. *Wholesale demand response mechanism*
2. Australia Energy Market Operator. *Project Jupiter*
3. Amber Electric. *What is Amber's SmartShift and how does it differ from a VPP?*
4. Discover Energy. *Discover VPP*

Jurisdictional Scan – Australia

Table 12. provides an overview of program-based compensation mechanisms in Australia. These mechanisms are either in pilot stages or are technology specific.

Table 12. Overview of program-based compensation mechanisms in Australia

Program-based Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
EnergyAustralia PowerResponse	Pilot program compensating for reducing usage during grid stress events	Smart appliances, flexible load like EV chargers
AGL Peak Energy Rewards	Pilot program that incentivizes customers for residential load reduction and automated control of devices during peak demand events	Smart appliances, flexible load like EV chargers
Cheaper Home Batteries Program	Provides a discount for up to 30% of the upfront cost of a small scale (5-10 kWh) battery system for residential commercial batteries	Battery storage

1. EnergyAustralia. *PowerResponse*
2. AGL. *Peak Energy Rewards*
3. Australian Government, Department of Climate Change, Energy, the Environment and Water, October 7, 2025. *Cheaper Home Batteries Program*

Jurisdictional Scan – Australia

A summary of the findings from the jurisdictional scan of Australia is provided below.

Summary of DER Compensation in Australia

With 26.8 GW of installed solar, Australia has one of the highest global penetrations of rooftop solar. The uptake of rooftop solar was driven by high FiT rates for solar energy, beginning in 2005. As uptake of the technology increased, the price of a standard solar module decreased which significantly reduced the cost for solar installations. The high FiT rates were phased out beginning in 2011 and have been replaced with retailer-set dynamic FiT rates that vary by location. Today in Australia, uptake of rooftop solar is driven by underlying prices rather than policy support. Australia has also implemented incentives for small-scale battery systems to increase adoption of batteries with rooftop solar.

Current initiatives such as the Controlled Load and Demand Charge Tariffs indicate a shift towards more dynamic and value-driven mechanisms. These measures aim to align DER compensation with system value and operational performance.

While DER penetration continues to grow, future projections indicate significant expansion. The Electricity Network Transformation Roadmap estimates that by 2027, over 40% of energy customers will use DER, increasing to more than 60% by 2050. By mid-century, DER could contribute up to 45% of Australia's electricity generation capacity.

1. EY Net Zero Centre, 2024. *From Chaos to Choreography: Why Australia needs to orchestrate distributed energy resources, and how it can be achieved*
2. Energy Networks Australia and Commonwealth Scientific and Industrial Research Organization, April 2017. *Electricity Network Transformation Roadmap*

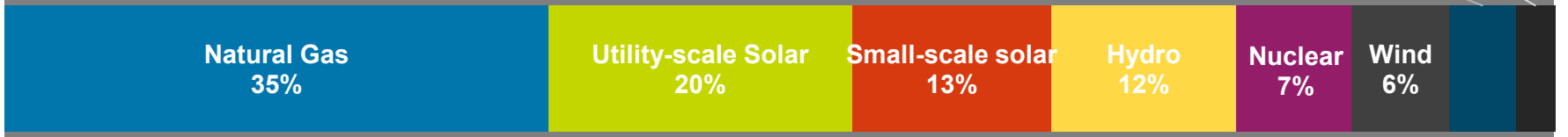
Jurisdictional Scan – California

Figure 7 provides a summary of California's energy profile, policy goals and major DER reforms.

Figure 7. Summary of California's Energy System and Overarching Policies

Policy Goal	Electricity System Overview
• **60%** clean electricity by 2030 and **100%** by 2045.[1] • **5 million** zero emission vehicles by 2030.[2] • **100%** of new passenger cars and light-truck sales to be zero-emission by 2035 and medium- and heavy-duty vehicles by 2045 where feasible.[3]	• The California Public Utilities Commission regulates investor-owned utilities. • The California Independent System Operator (CAISO) manages wholesale electricity markets and ensures grid reliability. • The California Energy Commission develops state energy policy, oversees publicly owned utilities, and supports clean energy innovation.

Fuel Mix (2024)[6]



Major DER Reforms

- Net metering was replaced with the Net Billing Tariff (NBT), shifting DER compensation to time-based export rates to ensure net metered customers appropriately contribute to costs independent of total energy volume.
- While long-term plans support co-optimization, current rules limit value stacking for DERs
- FERC's order 2222 enforced reforms around how DERs participate in the wholesale energy market, leading to DER Aggregation Framework adoption.

Energy Sector Facts[4,5,6,7,8]

- **98.6 GW** Total Installed Capacity
- **217 TWh** Total Generation
- **17.4 GW** Rooftop Solar Capacity
- **~253,000** Customer Battery Installations
- **~1.9 M** Electric Vehicles

* Other in fuel mix include unspecified, biomass, coal and petroleum

1. California Energy Commission. https://www.energy.ca.gov/data-reports/clean-energy-serving-california
2. California Air Resource Board. https://ww2.arb.ca.gov/our-work/programs/zero-emission-vehicle-fleet/about.
3. California Air Resource Board, August 25, 2022. https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035
4. US Energy Information Administration, 2025. Table 6.2. A. Net Summer Capacity of Utility Scale Units by Technology and State.
5. US Energy Information Administration. 2023. Electric Power Annual Table 3.7 Utility Scale Facility Net Generation for all sectors.
6. California Distributed Generation Statistics. https://www.californiadgstats.ca.gov/ . Fuel mix total may not add to 100% due to rounding.
7. California Energy Commission. California Energy Storage System Survey , Residential and Commercial Energy Storage Installations as of April 3, 2025.
8. California Energy Commission. 2024. Light-Duty Vehicle Population in California
9. US Energy Information Administration. Electricity Data Browser.

ONTARIO ENERGY BOARD

Jurisdictional Scan – California

Table 13 provides an overview of price-based compensation mechanisms in California.

Table 13. Overview of price-based compensation mechanism in California

Price-based Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
NBT[1]	Compensates exported energy via hourly Energy Export Credits based on grid value	Solar PV, Solar + Storage
TOU Pricing Plans[2]	Encourages strategic energy use based on time-varying rates.	All DER types
Virtual Net Energy Metering (VNEM)[3]	Allows tenants in multi-unit buildings to receive bill credits from a shared renewable system.	Solar PV, Solar + Storage
Virtual NBT[4]	Similar to VNEM but under net billing framework.	Solar PV, Solar + Storage
Net Metering Aggregation[5]	Aggregates multiple meters on contiguous properties to offset load with one system.	Distributed Generators (Solar PV, Wind, Fuel Cells, etc.)
Renewable Energy Self-Generation Bill Credit Transfer[6]	Public entities can transfer excess bill credits across meters	Renewable Distributed Generation
NEM Fuel Cell[7]	Provides bill credits for electricity exported from eligible fuel cell systems.	Fuel Cells
Renewable Energy Certificates	Tradable credits certifying 1 MWh of renewable generation for compliance or voluntary markets.	All renewable energy technologies

1. California Public Utilities Commission, 2025. *Net Energy Metering and Net Billing*
2. California Public Utilities Commission, July 2015. *Decision on Residential Rate Reform and Transition to Time-of-Use Rates*
3. California Public Utilities Commission, 2025. *Virtual Net Energy Metering*
4. California Public Utilities Commission, November 2023. *Decision Addressing Remaining Proceeding Issues*
5. Pacific Gas and Electric Company. *Net Energy Metering Aggregation Program*
6. California Public Utilities Commission, April 2010. *Resolution E-4283*
7. Pacific Gas and Electric Company. *Net Energy Metering for Fuel Cells*
8. California Energy Commission, January 2017. *Renewables Portfolio Standard Guidebook*

Jurisdictional Scan – California

DER compensation in California originated with Demand-Side Management programs in the 1970s that introduced TOU rates and load incentives. NEM 1.0 was formally established in 1996, marking the start of standardized rooftop solar compensation. Figure 8 illustrates the evolution of NEM in California. A 2021 report found that under traditional net metering, solar customers often pay less than the actual cost to serve them, leading other ratepayers to cover the difference, as shown in Figure 9.[2] This cost shift underscores the need for rate reform that reflects both the value and service costs of DERs. California's NBT was introduced to address this. Net billing compensates solar customers for excess electricity sent to the grid using hourly Energy Export Credits rates set by the California Public Utilities Commission (CPUC) based on hourly avoided-cost rates, which vary by time of day and season, reflecting real-time needs. While typically lower than retail prices, Energy Export Credits can exceed retail prices during peak demand periods. Customers lock in their hourly Energy Export Credit rates based on their interconnection year and may receive Net Surplus Compensation if annual exports exceed usage.

Figure 8. Evolution of net metering in California

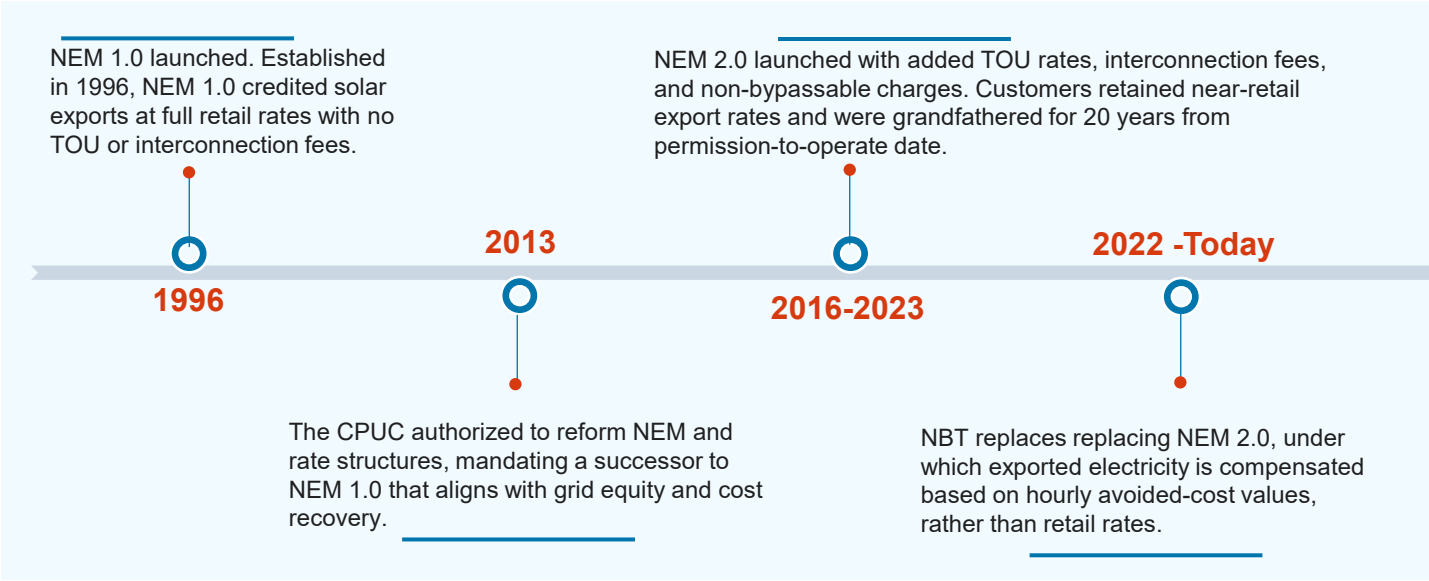
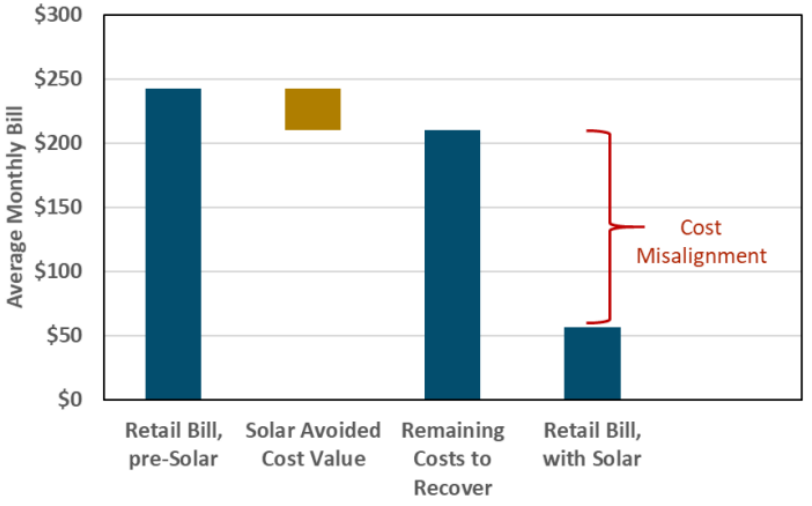


Figure 9. Average Residential Customer Annual Bill (With and Without Solar), and Remaining Non-Avoidable Costs After Accounting for Solar Value[2]



1. California Public Utilities Commission, 2025. Net Energy Metering and Net Billing
2. California Public Utilities Commission, January 28, 2021. *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California*

ONTARIO ENERGY BOARD

Jurisdictional Scan – California

Table 14 provides an overview of procurement and market-based compensation mechanisms in California. These mechanisms allow DERs in California to participate in demand response programs across both utility and wholesale markets, enabling access to real-time, day-ahead and ancillary services markets. DERs that do not meet minimum size thresholds participate via aggregators. Utility-managed demand response programs, such as Reliability Demand Response Resources and Proxy Demand Resources, are used to meet resource adequacy requirements and bid into the CAISO markets as supply. Following FERC Order 2222, CAISO enabled DER aggregations by reducing the minimum capacity threshold from 500 kW to 100 kW and implementing safeguards against duplicate compensation across retail and wholesale markets.[1] In summer 2024, utility-managed demand response accounted for 76% of demand response used for resource adequacy, representing about 2% of total system capacity.[2] Market participants are compensated either directly or through aggregators via bill credits, rate reductions or cash payments.

Table 14. Overview of procurement and market-based compensation mechanisms in California

Procurement and Wholesale Market Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
CAISO Energy & Ancillary Services Markets[3]	DERs participate in real-time/day-ahead energy and ancillary services markets.	All DERs participating via aggregators if minimum size threshold is not met
Reliability Demand Response Resources	Utility-managed demand response programs used for resource adequacy.	Demand Response
Proxy Demand Resources	DR resources bid into CAISO markets as supply.	Demand Response

1. California Independent Electricity System Operator, 2024. New Heterogeneous DER Aggregate Type to Support Underlying DERs and Distributed Curtailments Resources
2. California Independent Electricity System Operator, March 14, 2025. *Demand response issues and performance 2024*

Jurisdictional Scan – California

Table 15 provides an overview of program-based compensation mechanisms in California. These mechanisms include demand response programs for various services, mainly managed by utilities, third parties or aggregators. Offerings include load reduction during peak periods or emergencies, energy bill credits and rate discounts, capacity commitments, financial incentives for solar and storage, support for low-income and disadvantaged communities, automated load control technologies, TOU and critical peak pricing structures, voluntary emergency load reduction with compensation and resiliency-focused incentives.

Table 15. Overview of program-based compensation mechanisms in California

Program-based Mechanisms		
Mechanism	**Description**	**Eligible DER Type**
Solar on Multifamily Affordable Housing[1]	Incentives for solar installations on multifamily housing, benefiting low-income tenants.	Solar PV
Self-Generation Incentive Program[1]	Financial incentives for installing generation and storage technologies, with enhanced support for equity users.	Battery storage, Fuel cells, Combined heat and power (CHP), Renewable distributed generation
Automated Response Technology[2]	Enables residential users to automate energy reductions during peak periods.	Smart thermostats, Load control devices
Capacity Bidding Program[3]	Commercial and institutional users bid load reductions for incentives.	Load curtailment, Building management systems
Critical Peak Pricing[4]	Higher rates during critical peak hours to incentivize reduced consumption based on high peak event alert	All DER types
SmartRate & Peak Day Pricing[5]	Encourages load shifting during peak days/events compensated through discounted seasonal electricity rates.	Flexible loads, Smart devices, Storage
The Emergency Load Reduction Program[6]	Compensates electricity customers for voluntarily reducing energy use during grid emergencies declared by CAISO which serves as a last-resort tool to prevent outages.	Flexible loads, Smart devices, Storage

1. California Distributed Generation Statistics. https://www.californiadgstats.ca.gov/
2. Pacific Gas and Electric Company, December 11, 2024. ELECTRIC SCHEDULE E-ART
3. Southern California Edison, 2024. Capacity Bidding Program
4. Sacramento Municipal Utility District. Critical Peak Pricing
5. Pacific Gas and Electric Company. SmartRate
6. CPUC. Emergency Load Reduction Program

ONTARIO ENERGY BOARD

Jurisdictional Scan – California

A summary of the findings from the jurisdictional scan of California is provided below.

Summary of DER Compensation in California

California has deployed over 17 GW of behind-the-meter solar and 15 GW of battery storage, reshaping local utility demand.[1] After it was determined that net metered solar customers often pay less than the cost to serve them, California transitioned from net metering to net billing. Net billing compensates electricity exports at hourly rates that differ from rates applied to consumed electricity. Legacy net metering programs (NEM 1.0 and 2.0) were projected to contribute to an $8.5 billion cost shift from net metered customers to non-net metered customers by the end of 2024.[2] Since it was determined that eliminating this cost shift would be very difficult to achieve without severe bill impacts and could make it challenging to maintain a viable customer-sited renewable generation industry, the transition to net billing was done gradually and had an external transitional support mechanism to enable a reasonable payback period for customers investing in onsite renewable generation.[3]

FTM batteries dominate California's Non-Generator Resource market, providing energy, capacity and ancillary services with streamlined integration. Their revenue is primarily derived from energy arbitrage on days with large fluctuations between afternoon and evening market prices, with some additional revenue derived from regulation services and bid cost recovery.

The CAISO's DER aggregation model, developed in response to FERC Order 2222, enables aggregated DERs to participate in wholesale markets, expanding their operational role beyond behind-the-meter configurations. Together, these initiatives establish a regulatory and technical foundation for scaling DER integration in California facilitating market participation, informing distribution system planning, and advancing load flexibility and customer engagement.

1. California Distributed Generation Statistics. *https://www.californiadgstats.ca.gov/*
2. The Public Advocates Office, August 22, 2024. *Rooftop solar incentive to cost customers without solar an estimated $8.5 billion by the end of 2024*
3. California Public Utilities Commission, January 28, 2021. *Alternative Ratemaking Mechanisms for Distributed Energy Resources in California*

ONTARIO ENERGY BOARD

Part 2: DER Delivery Rates

Context

Context

The following section summarizes the analysis and key considerations that informed the OEB's draft observations and discussion questions on DER delivery rates. This section is organized by the components summarized in the table below.

Context	*Provides a contextual overview of i) the Minister's directive to the OEB, ii) the existing elements of the DER delivery rates framework in Ontario, and iii) key terms, approach and considerations.*
Connection Cost Responsibility	*Describes connection cost responsibilities faced by distribution and transmission-connected electricity resources and loads and provides an update on the OEB's review of Ontario's connection cost responsibility rules.*
Base Distribution Rates for FTM Generation	*Describes base distribution rates for front of the meter generation (FTM; generation that is directly connected to a distribution system).*
Base Distribution Rates for FTM Energy Storage	*Describes base distribution rates for front of the meter energy storage (energy storage that is directly connected to a distribution system).*
Specialized Distribution Delivery Rates for DERs	*Describes specialized distribution rates that apply to DERs. The current distribution rate framework features limited instances where distribution-connected generators are charged specialized rates: Hydro Ottawa's monthly generator service charge, the DGen rate class applied by Alectra Brampton and Hydro One, and the microFIT charge.*
Delivery Rates for BTM Resources	*Describes delivery rates for behind-the-customer meter (BTM) DERs, including RTSRs, standby rates and bypass compensation.*
Demand-Side Resources	*Situates loads that host dynamic electric load-modifying technologies or practices falls within the overall subject of delivery rates for load customers.*
On the Issue of Grid Services	*Addresses item #11 of the IEP implementation directive, which specifically refers to demand/delivery charges for resources that provide grid services.*

Context – IEP Directive and Objectives

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
Specialized Distribution Delivery Rates for DERs
Delivery Rates for BTM Resources
Demand-Side Resources
On the Issue of Grid Services

This section provides a contextual overview of i) the Minister's directive to the OEB, ii) the existing elements of the DER delivery rates framework in Ontario, and iii) key terms, approach and considerations.

IEP Directive and Objectives of DER Delivery Rates Review

DER delivery rates are the OEB-approved electricity distribution and transmission rates that DERs pay in Ontario.

The OEB is reviewing DER delivery rates as it prepares a report to the Minister of Energy and Mines to identify recommendations or provide an update on actions by the OEB regarding Ontario's overall DER regulatory and compensation frameworks.

The OEB's review of DER delivery rates specifically responds to the IEP implementation directive's requirement for the OEB to consider "demand/delivery charges for resources that provide grid services (e.g., DER and storage)."

The OEB aims to achieve one or more of the following in its review of DER delivery rates:

- identify existing DER delivery rates in Ontario
- affirm existing DER delivery rates where appropriate
- propose to clarify existing DER delivery rates where they are unclear
- propose to update existing DER delivery rates to account for the passage of time, where necessary
- propose to establish new delivery rates where gaps have been identified.

Context – Background on Transmission Rates

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
Specialized Distribution Delivery Rates for DERs
Delivery Rates for BTM Resources
Demand-Side Resources
On the Issue of Grid Services

Background on DER Delivery Rates - Transmission

Ontario has a long-standing delivery rates framework for electricity resources that are located on the transmission system.

This is because most of Ontario's electricity resources, in terms of installed capacity and annual energy production, are located on the transmission system.

The OEB established Ontario's transmission rates framework 25 years ago through an adjudicative proceeding that set Hydro One's first transmission revenue requirement following the breakup of Ontario Hydro (RP-1999-0044). That framework continues to apply today, though it has evolved over time.

Key elements of Ontario's transmission rates framework include that rates shall

- recover transmitter revenue requirements;
- be applied on a uniform basis across the province;
- be allocated into specified asset pools (network, transformation, line); and
- be derived based on specified charge determinants.

Ontario's transmission rates framework also establishes the premise of gross load billing and net load billing for transmission-connected loads with embedded generators, and more. Importantly, it also provides that loads pay for transmission rates, not generators (with some exceptions, such as station service load at generating stations).

Ontario's transmission rates framework is summarized in the Uniform Transmission Rates (UTR), which are set by the OEB (usually twice per year), and in the Transmission System Code (TSC).

Context – Background on Distribution Rates

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
Specialized Distribution Delivery Rates for DERs
Delivery Rates for BTM Resources
Demand-Side Resources
On the Issue of Grid Services

Background on DER Delivery Rates - Distribution

Ontario's distribution delivery rates framework for DERs is articulated across a greater variety of documents (than the transmission delivery rates framework), including:

- OEB-approved electricity distribution Rate Orders;
- The Distribution System Code (DSC); and
- Other OEB Decisions.

There has not been the same historical impetus to articulate and review delivery rates policies for resources that are located on the distribution system as there has been for resources on the transmission system (because most of the province's electricity resources are transmission-connected).

Looking ahead, the OEB expects more electricity resources to be deployed on the distribution system than they have been in the past.

The OEB holds this expectation considering the energy transition and recognizing the various initiatives across the province to facilitate the greater adoption of DERs where appropriate, and to further integrate DERs into electricity system operations and markets.

The component of the IEP implementation directive that addresses DER delivery rates adds further reason for the OEB to consider delivery rates for electricity resources that are located on distribution systems. It also provides additional context for exploring opportunities to provide greater clarity to customers and to the sector, to reduce undue barriers to participation, to support planning and investment across all levels of the power system and to ensure appropriate delivery rates for DERs.

Context – Developing a DER Delivery Rates Framework

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
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Delivery Rates for BTM Resources
Demand-Side Resources
On the Issue of Grid Services

Developing a DER Delivery Rates Framework

Elements of Ontario's DER delivery rates framework exist today:

- In some cases, it might be that those elements can be affirmed or clarified or updated (e.g., to account for the passage of time) because of the OEB's current review.
- In other cases, there may be gaps that call for new elements of the DER delivery rates framework to be established.

The OEB will consider feedback from stakeholders as it develops a report back to the Minister of Energy and Mines on IEP implementation directive item #11.

Delivery rates are set by the OEB. The OEB expects any changes to DER delivery rates would be made by the OEB through appropriate processes, such as a hearing, policy consultation or generic hearing, or others as applicable, to address some or all the opportunities more thoroughly, with appropriate stakeholder participation and over a suitable period of time.

Context – DER Descriptions

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Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
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On the Issue of Grid Services

DER Descriptions

- Electricity generating technologies, electric storage technologies, or dynamic electric load-modifying technologies or practices hosted by a customer (such as a home or business) that is connected to a distribution system.
- Also include electricity generating technologies or electricity storage technologies that are directly connected to a distribution system (i.e., rather than to an end-use customer's premises within a distribution system).
- Can include but are not limited to solar photovoltaics, combined heat and power plants, backup generators, energy storage, EVs and consumer devices that can reduce or increase electricity use on demand.
- Energy efficiency measures are not considered to be DERs because their performance is not dynamically variable.

Descriptions of the differences between behind-of-the-meter vs. front-of-the-meter DERs

- DERs that are installed on the distribution load customer's side of an ownership demarcation point (such as a revenue meter) are referred to as behind-the-meter DERs.
    - Examples include rooftop solar panels or home batteries that provide on-site service to a specific home or business. Behind the meter DERs tend to primarily serve the energy needs of the customer that hosts them.
- DERs that are installed on the distribution utility's side of an ownership demarcation point are referred to as front of the meter DERs.
    - These are typically larger energy systems (compared to behind the meter DERs), such as solar farms, that are connected directly to the distribution system and that inject electricity into the distribution system.

Context - Considerations

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
Specialized Distribution Delivery Rates for DERs
Delivery Rates for BTM Resources
Demand-Side Resources
On the Issue of Grid Services

Proposed DER Perspectives to be Considered

- The OEB proposes to consider DERs from the perspectives of (a) their electrical location and (b) their function.

  (a) In terms of electrical location, we propose to consider both front of meter and behind the meter DERs.

  (b) In terms of function, we propose to consider front of meter generating technologies and storage technologies (i.e., DER technologies that inject electricity directly into the grid, and DER technologies that directly inject and withdraw electricity from the grid).

- For behind the meter DERs, we propose to consider generating technologies, storage technologies and dynamic load-modifying technologies or practices. We will also consider behind the meter DERs that provide load displacement only, as well as behind the meter DERs that displace load and inject into the distribution system (for example, through arrangements akin to net metering).

Additional Considerations

- While the OEB proposes to focus on rates, which are within the OEB's mandate, the OEB also proposes to identify policy opportunities to government, as applicable, by considering rates in the context of the DER-related policy objectives that are set out in the Ontario government's 2025 IEP and IEP implementation directive to the OEB.

Context - Types of DER Delivery Costs and Rates

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
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Demand-Side Resources
On the Issue of Grid Services

Proposed Types of DER Delivery Costs and Rates to be Considered

The OEB proposes to consider all key types of delivery costs and rates related to DERs in Ontario. These include:

1. Connection costs: the one-time costs that generator or load customers pay to an electricity distributor for connecting to a distribution system. Connection cost responsibilities are set out in agreements between customers and electricity distributors, in accordance with the OEB's Distribution System Code (DSC).

2. Base rates: the recurring rates that distribution customers pay to an electricity distributor for maintaining and operating the distribution network and delivering electricity to customers. The rates are approved by the OEB and are outlined in the Tariff of Rates and Charges of each electricity distributor. Where applicable, the rates include Retail Transmission Service Rates (RTSRs) and Low Voltage Charges (LVs). RTSRs are charges that a distributor applies to its customers to recover the costs of wholesale transmission service. LVs are charges that an embedded distributor applies to customers to recover the costs of distribution services provided to it by its host distributor.

3. Specialized rates: where applicable, the rates that apply to specific DER programs or types. The rates typically cover an electricity distributor's metering and settlement costs and its costs of managing DER accounts. Examples include the microFIT charge, DGEn charge and Monthly Generator Services charge.

4. Behind the meter-related rates: the rates associated with DERs that operate on the customer side of the meter. An example is the standby rate. Standby rates are paid by distribution customers that have load displacement generation. The standby rates cover the distributor's cost of maintaining grid availability when the customer's load displacement generation is not producing or is underperforming.

Context – Rate Design Principles

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
Base Distribution Rates for FTM Energy Storage
Specialized Distribution Delivery Rates for DERs
Delivery Rates for BTM Resources
Demand-Side Resources
On the Issue of Grid Services

Proposed Rate Design Principles

The OEB proposes four rate design principles for the purposes of this document.

The principles will help inform the OEB's consideration of whether any clarifications, updates or other changes might be warranted to existing DER delivery rates.

The principles will also help guide the OEB's consideration of any gaps in Ontario's DER delivery rates framework and of options for addressing them. The principles are meant to encompass all the Bonbright principles of a sound rate structure.

Proposed principles:

1. Cost Recovery: Rates should provide each distributor with a reasonable opportunity to recover its prudently incurred costs of providing service to its customers (including a fair return).
2. Fairness: customers should, in general, pay rates for distribution service that reflect the costs they cause. This principle is often referred to as the "user pay" or "cost causality" or "beneficiary pays" principle.
3. Efficiency: Rates should encourage customers to maximize use of existing assets and also encourage use of the distribution system in ways that lead to rational growth.
4. Simplicity: A distributor's rates should be practical, clear and uncontroversial

Context – Considerations on Tx and Dx Harmonization

Context
Connection Cost Responsibility
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On the Issue of Grid Services

Proposed Considerations on Greater Harmonization Between Transmission and Distribution Rates Frameworks for Electricity Resources

Where applicable, the OEB proposes to consider opportunities to more closely harmonize distribution and transmission delivery rates frameworks for electricity resources (e.g., generation, storage, dynamic load, DER).

Where not already the case, greater harmonization might be appropriate because:

- Transmission and distribution systems are physically analogous and tend to be connected to each other – their rates frameworks might warrant more analogous treatment as well.
- Ontario has longstanding experience with delivery rates for resources that are located on the transmission system. There might be opportunities to leverage that experience in the emerging context of DERs.
- Greater harmonization might help address any unintended consequences and undue seams or barriers associated with having discrete, less-harmonized regulatory regimes for assets and services that are physically and operationally continuous.
    - This would be especially relevant in the event of greater integration of distribution and Distribution System Operator (DSO) and/or wholesale electricity markets, and greater DER participation in wholesale and/or DSO markets.

Context – Considerations on Tx and Dx Harmonization

Context
Connection Cost Responsibility
Base Distribution Rates for FTM Generation
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Additional Considerations on Greater Harmonization Between Transmission and Distribution Rates Frameworks for Electricity Resources

On the other hand, there might be instances where greater harmonization between transmission and distribution system delivery rates frameworks for resources might not be appropriate.

- This can be due to fundamental differences in the physical topology of transmission and distribution systems.
- Variations in the types of services provided by transmission and distribution utilities, or other specific operational, regulatory or business circumstances, may further justify maintaining distinct frameworks.

The OEB will therefore remain open to considering opportunities for greater harmonization between transmission and distribution delivery rate frameworks where such alignment is practical and contextually appropriate.

However, the OEB will also consider the importance of respecting legitimate differences in system design, service offerings, operational contexts and any other relevant considerations.

ONTARIO ENERGY BOARD

Part 2: DER Delivery Rates

Observations, Updates and Discussion Questions

Connection Cost Responsibility – Current Approach

Context	*The following section describes connection cost responsibilities faced by distribution and transmission-connected electricity resources and loads and provides an update on the OEB's review of Ontario's connection cost responsibility rules.*
Connection Cost Responsibility	**Distribution System Connections** The cost responsibility for connecting generators and load customers to an electricity distribution system is governed by the DSC. The DSC outlines who pays for what when new or modified connections are made to the distribution system. The guiding principle that underlies the allocation of the costs associated with distribution connection investments is "beneficiary pays," which means that persons who benefit from an infrastructure investment should pay the full cost of the investment. Costs should not be allocated to any consumer, distributor or generator that will not benefit from the investment.
Base Distribution Rates for FTM Generation	
Base Distribution Rates for FTM Energy Storage	
Specialized Distribution Delivery Rates for DERs	
Delivery Rates for BTM Resources	
Demand-Side Resources	
On the Issue of Grid Services	

Connection Cost Responsibility – Current Approach

Context	***Connections, Expansions, Enhancements***
Connection Cost Responsibility	Chapter 3 of the DSC provides rules on cost responsibilities under three sections: connections, expansions and enhancements.
Base Distribution Rates for FTM Generation	• Connections refer to the addition or modification of assets used to connect a customer to the existing main distribution system, and consist of the assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with that customer. Connecting customers pay for connection costs.
Base Distribution Rates for FTM Energy Storage	• Expansions are modifications or additions to the main distribution system in response to one or more requests for additional customer connections that otherwise could not be made (e.g., by increasing the length of the main distribution system). When a distributor is preparing an offer to connect a customer that involves an expansion, it must perform an economic evaluation (set out in Appendix B of the DSC) to determine the costs that the customer(s) will be required to pay for the expansion work (i.e., the capital contribution). The purpose of the economic evaluation is to assess the expansion project against the beneficiary pays principle so the customer can pay the appropriate capital contribution.
Specialized Distribution Delivery Rates for DERs	• Enhancements are part of distributors' ongoing efforts to plan and build the distribution system for reasonable load growth and improve system reliability. The cost of the enhancement work is expected to be paid for by distributors, and the main purpose of this work is to improve system operating characteristics or relieve system capacity constraints.
Delivery Rates for BTM Resources	
Demand-Side Resources	
On the Issue of Grid Services	

Connection Cost Responsibility – Current Approach

Context	***Renewable Enabling Improvements***
Connection Cost Responsibility	Amendments to the DSC in 2009 and 2010 shifted some of the costs of connecting renewable energy generation facilities from generators to distribution ratepayers (EB 2009-0077). Section 3.3.3 of the DSC states that distributors shall not charge generators a capital contribution for Renewable Enabling Improvements (REIs).
Base Distribution Rates for FTM Generation	REIs are modifications or additions to a distributor's main distribution system to accommodate generation from renewable energy generation facilities. REIs are limited to the following: • Electrical protection equipment • Voltage regulation transformer controls or station controls • Protection against islanding (transfer trip) • Bidirectional reclosers • Tap-changer controls or relays • Replacing breaker protection relays • SCADA system design, construction and connection • Other modifications to allow for and accommodate two-way electrical flows • Communications systems to facilitate the connection of renewable generation
Base Distribution Rates for FTM Energy Storage	
Specialized Distribution Delivery Rates for DERs	
Delivery Rates for BTM Resources	
Demand-Side Resources	
On the Issue of Grid Services	REI investments are funded by distributors and recovered from distribution customers through rates.

Connection Cost Responsibility – Current Approach

Context	***Renewable Expansion Cost Caps***
Connection Cost Responsibility	The DSC provides that renewable generators are not required to contribute to a distribution system expansion related to their connection if the cost of the expansion is less than the "renewable energy expansion cost cap."
Base Distribution Rates for FTM Generation	In relation to a renewable energy generation facility, a renewable energy expansion cost cap is a dollar amount determined by multiplying the total nameplate rated capacity of the facility by $90,000 per MW.
Base Distribution Rates for FTM Energy Storage	If the cost of expanding the distribution system to accommodate the generator exceeds the renewable energy expansion cost cap, the generator must pay the portion above the cap. Expansion costs below the cap are covered by the distributor and recovered through distribution rates.
Specialized Distribution Delivery Rates for DERs	***Renewable Energy Generation Facilities***
Delivery Rates for BTM Resources	The Electricity Act defines a renewable energy generation facility as "*a generation facility that generates electricity from a renewable energy source"*, which include "*wind, water, biomass, biogas, biofuel, solar energy, geothermal energy, tidal forces and such other energy sources as may be prescribed by the regulations.*"
Demand-Side Resources	Energy storage is not considered as a renewable energy generation facility for the purpose of cost responsibility of connection costs.
On the Issue of Grid Services	

Connection Cost Responsibility – Current Approach

Context	***Renewable Generation Connection Rate Protection***
Connection Cost Responsibility	In 2009, the Ontario government introduced a mechanism under section 79.1 of the OEB Act, whereby some of the OEB-approved costs incurred by an electricity distributor for the purpose of connecting a renewable energy generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor making the investment. Eligible investments relate to the REIs and renewable connection cost caps described above.
Base Distribution Rates for FTM Generation	Subsection 79.1(1) of the Ontario Energy Board Act, 1998 (the OEB Act) states that the OEB may provide Renewable Generation Connection Rate Protection (RGCRP) compensation amounts to eligible distributors. Ontario Regulation 330/09 sets out the framework for the determination of the amount which may be recovered from all provincial ratepayers. In particular, the difference between:
Base Distribution Rates for FTM Energy Storage	(a) the costs associated with making an eligible investment and determined to be the responsibility of the distributor in accordance with the DSC, and
Specialized Distribution Delivery Rates for DERs	(b) the amount the OEB determines to represent the 'direct benefits' that accrue to prescribed consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.
Delivery Rates for BTM Resources	The OEB determines the eligibility of the connection investment made by each distributor in its distribution rate decisions and issues an order to the Independent Electricity System Operator (IESO) to collect and disburse specific amounts based on the approved entitlements
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Connection Cost Responsibility – Related Initiatives

Context	**OEB Review of Distribution System Connections** The OEB is currently leading two major initiatives aimed at improving how customers connect to the province's electricity distribution grid: The Distribution Customer Connections Review will conduct a comprehensive assessment of the electricity distributor processes and requirements for connecting load customers to the distribution grid. This review is in response to stakeholder feedback and the Minister of Energy and Mines' Integrated Energy Plan Directive. Building on the OEB's previous initiatives that considered connections specific to electric vehicle charging and housing developments, this review will examine connection processes for all types of load customers across the province. The review will assess the reasonableness and timeliness of distributor procedures to connect customers and recommend changes to streamline and improve connection processes. In parallel, the DER Connections Review focuses on facilitating the integration of DERs by addressing any barriers to their connection and improving the connection process into the distribution system. Launched in 2019, this initiative engaged with distributors, transmitters, DER providers and consumer groups to propose changes streamlining the process to connect DERs. Recent efforts have been focused on enabling higher DER penetration through exploring different approaches to address local capacity issues. In 2025, the OEB began development of the Centralized Capacity Information Map (CCIM) to improve transparency around available distribution system capacity. The CCIM will be designed to support informed planning by developers and customers and reduce barriers to timely integration of DERs and load connections. Additionally, the OEB launched a technical discussion with stakeholders to provide clarifications on the cost responsibility rules for DER connections that are defined in the DSC.
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Connection Cost Responsibility – Current Approach

Context	**Transmission System Connections** The Transmission System Code (TSC) sets out the requirements, standards, terms and conditions of a transmitter's obligations to connect consumers to the transmission system, including performance standards, technical requirements, and rules for expansions and connections. Section 6.3 of the TSC sets out the cost responsibility rules for transmission connection assets and network assets. Cost responsibility rules follow the "beneficiary-pays" principle such that a transmission customer that benefits from the transmission asset is allocated the full cost of that asset. ***Network Facilities*** Costs associated with additions or upgrades to network facilities are typically allocated to all transmission ratepayers since they form part of a transmission system that is shared by all users. The TSC also contemplates that some assets in a network facility may serve a connection function and costs are allocated to the connecting customer. In such cases, the TSC refers to it as "exceptional circumstances."
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Connection Cost Responsibility – Current Approach

Context	***Connection Facilities***
Connection Cost Responsibility	Costs associated with new or modified connection facilities are allocated to the connecting customer since they are dedicated to one or a small group of customers (i.e., generator or load or storage). • The customer may be required to make a capital contribution before the connection facility is built, subject to an economic evaluation. • Where a transmitter demonstrates in an application to the OEB that the connection facility investment also provides benefits to the network (e.g., reliability), some of the costs are allocated to all ratepayers through the network pool. In general, the TSC requires generators to provide their own dedicated connection to the transmission system and pay the full cost of transmitter's connection facilities upfront. This incentivizes generators to reduce connection costs (and thereby reduce its overall generation costs) by locating near the transmission facilities. Load customers pay through a combination of connection rates (collected over an economic evaluation period) and upfront capital contribution. • The TSC specifies the economic evaluation methodology to be used by a transmitter to calculate the upfront capital contribution to be collected from a connecting customer toward the cost of a new or modified connection facility. • Economic evaluation is used to determine that the connection facility is economically viable and fair to both the transmitter (and its ratepayers) and the connecting customer. The evaluation is essential to ensure that the costs of connection are appropriately recovered and do not unfairly burden existing ratepayers.
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Connection Cost Responsibility – Related Initiative

Context	***OEB Review of Transmission System Connections***
Connection Cost Responsibility	The OEB is undertaking a review of the TSC to enhance and clarify the implementation of cost responsibility rules for connections (EB-2024-0126)
Base Distribution Rates for FTM Generation	The OEB is seeking to provide additional clarity to customers and transmitter with respect to asset classification (i.e., network vs connection) by revising the definitions and enhancing the implementation of "beneficiary-pays" principle.
Base Distribution Rates for FTM Energy Storage	Other targeted enhancements include clarifying the "exceptional circumstances" under which a transmitter may allocate costs of a network facility investment to a connecting customer. This work will increase predictability of cost responsibility needs for impacted customers and streamline the utility planning process.
Specialized Distribution Delivery Rates for DERs	The review may result in amendments to the TSC and potentially other guidance to the industry, if required, through consultations with industry stakeholders. This is also consistent with item #8 on the Ontario government's IEP directive to the OEB.
Delivery Rates for BTM Resources	Moreover, the OEB is updating Appendix 5 to the TSC which prescribes the financial risk assessment methodology a transmitter employs during the economic evaluation process. The current methodology for non-credit-rated entities relies on outdated formulae. The OEB is modernizing this approach by requiring transmitters to use reliable, widely adopted credit risk assessment tools that combine quantitative risk modelling and qualitative analysis to produce risk assessments that are timely, prudent and incorporate qualitative or supplementary factors such as government support, IESO contract or collateral.
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Connection Cost Responsibility – Current Thinking

Context	**Observations, updates and discussion questions**
Connection Cost Responsibility	Connection cost responsibility frameworks exist for Ontario's distribution and transmission systems, and they are consistent with each other. The OEB has initiated consultations to review some aspects of transmission and distribution cost responsibility and has identified additional aspects that it plans to review in the future. *What should the OEB consider when reviewing policies under Ontario Regulation 330/09 related to the treatment of distributed generation when powered by renewable energy sources - Renewable Enabling Improvement cost recovery, renewable energy expansion cost cap, Generation Connection Rate Protection, the scope of the Regulation - in light of changes in DER deployment and technology in Ontario since these initiatives were introduced?*
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Base Distribution Rates for FTM Generation – Current Approach

Context	*The following section describes base distribution rates for front of the meter generation (FTM; generation that is directly connected to a distribution system).*
Connection Cost Responsibility	Based on a sample review, generation that is directly connected to a distribution system in Ontario does not pay base distribution rates. Base distribution rates are paid by load customers instead (e.g., customers that draw power from the distribution grid for their own use). This is consistent with how responsibility for paying 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). • Base transmission rates are paid by load customers instead. • 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.
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Base Distribution Rates for FTM Generation - Current Thinking

Context	**Observations, updates and discussion questions**
Connection Cost Responsibility	The OEB proposes to support the existing exemption of distribution-connected generation from base distribution rates, for the same reason cited by the OEB in its Decision on RP-1999-0044.
Base Distribution Rates for FTM Generation	RP-1999-0044 established that generators shall be exempt from transmission charges, since the charges would be borne by the load customers through the pricing of the commodity. There is a parallel to distribution-connected generation: the cost of distribution rates would be recovered from load customers through the commodity price.
Base Distribution Rates for FTM Energy Storage	The OEB also proposes to support the existing consistency between Ontario's distribution and transmission rates frameworks regarding the treatment of base rates for directly connected generation. Consistency in this area avoids undue differences in delivery rate treatment between transmission and distribution connected generation and, in the process, avoids undue barriers to DERs.
Specialized Distribution Delivery Rates for DERs	*Is this approach appropriate and has the OEB missed anything that might justify a different conclusion?*
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Base Distribution Rates for FTM Storage – Current Approach

Context	*The following section describes base distribution rates for front of the meter energy storage (energy storage that is directly connected to a distribution system).*
Connection Cost Responsibility	Energy storage that is directly connected to a distribution system in Ontario pays base distribution rates 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 responsibility for paying base transmission rates will be assigned in Ontario's transmission rates framework: beginning in 2026, base transmission rates will not be paid by transmission-connected energy storage facilities (with some exceptions, such as station service load). They will be paid by load customers instead. The OEB considered transmission rates for energy storage in phase two of its Generic Hearing on Uniform Transmission Rates (EB-2022-0325). In its March 2025 Decision, the OEB: • Established that transmission connected storage facilities will be exempt from transmission service charges when they provide physical 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. • Stated that the facilities require energy withdrawals to provide these physical services and for their generation-related capabilities.
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Base Distribution Rates for FTM Storage – Current Thinking

Context	**Observations, updates and discussion questions**
Connection Cost Responsibility	A base distribution rates framework exists for front-of-the-meter electricity storage: front-of-the-meter electricity storage pays base distribution rates when it withdraws electricity.
Base Distribution Rates for FTM Generation	This is not consistent with the framework that will be in place on the transmission system beginning in 2026.
Base Distribution Rates for FTM Energy Storage	The OEB is working with the IESO to co-ordinate the implementation of an exemption to transmission charges for transmission-connected energy storage facilities when these facilities are scheduled for operating reserve, providing reactive power support, providing regulation service, responding to a real-time IESO energy dispatch or responding to an IESO reliability directive beginning in 2026. This co-ordination and implementation activity is in accordance with the OEB's Decision and Order on Phase 2 of the Generic Hearing on Uniform Transmission Rates (EB-2022-0325).
Specialized Distribution Delivery Rates for DERs	Establishing consistency between Ontario's distribution and transmission rates frameworks in this area will remove undue differences in delivery rate treatment between transmission- and distribution-connected energy storage and will avoid undue barriers to DERs.
Delivery Rates for BTM Resources	*Should the OEB propose that energy storage that is directly connected to a distribution system in Ontario also be exempt from paying base distribution rates, just as transmission-connected energy storage has been exempted from paying transmission rates per the OEB's decision on EB-2022-0325?*
Demand-Side Resources	
On the Issue of Grid Services	*Should the OEB leverage lessons from the work that the OEB and the IESO are doing to co-ordinate and implement the exemption to transmission-connected storage? Should the OEB consider exempting front of meter electricity storage from paying Retail Transmission Service Rates in the more immediate term?*

Base Distribution Rates for FTM Storage – Current Thinking

Context	OEB staff's submission in EB-2022-0325 informs the OEB's current exploration of questions related to exempting distribution-connected storage from base delivery rates.
	
	In its submission dated October 16, 2024, OEB staff argued that the rationale for exempting transmission-connected generators from transmission charges in Ontario has parallel relevance for energy storage facilities.
	
	• Like transmission-connected generators, transmission-connected energy storage facilities also would be expected to consider transmission charges as an input to their generation offers, thus placing those costs onto load customers.
	  ◦ OEB staff submitted that, for an energy storage facility, the costs associated with charging the facility are its "fuel cost." This fuel cost would include the commodity cost of the energy and any associated charges. If an energy storage facility were to incur transmission charges to withdraw energy, this cost would logically be included when the facility offers energy back to the market at its marginal cost.
	• OEB staff also submitted that offers to generate electricity from a storage facility would also consider the efficiency of its units
	  ◦ The delivery rates would be amplified as one unit of energy to charge the facility would result in less than one unit of energy to offer into the market.
	  ◦ Therefore, any transmission rates incurred by an energy storage facility would be similarly borne by the load customers, amplified in accordance with the efficiency of the storage facility.

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This section describes specialized distribution rates that apply to DERs. The current distribution rate framework features limited instances where distribution-connected generators are charged specialized rates: Hydro Ottawa's monthly generator service charge, the DGen rate class applied by Alectra Brampton and Hydro One, and the microFIT charge.

Hydro Ottawa's Monthly Generator Service Charge

Hydro Ottawa's monthly generator service charge, first introduced in Hydro Ottawa's 2016-2020 Custom IR Application, is a fixed charge reflecting the costs of managing generation accounts on a monthly basis, specifically settlement services for the provisions of finance, accounting, billing and metering.

Hydro Ottawa's monthly generator service charges vary by IESO program – Net-Metering Service Charge, microFIT, FIT, and Hydro Electric Contract Initiative (HCI), Renewable Energy Standard Offer Program (RESOP), and Other Energy Resource Service charges.

Note that Hydro Ottawa proposes to remove the net metering charge in its 2026-2030 application, in which existing net metering generators will be absorbed within the microFIT and FIT charge classes.

- As of November 1, 2021, Hydro Ottawa stopped charging the monthly service charge to Net Metering customers.
- Net metering customers, unlike other generation customers, also incur a monthly fixed service charge based on the distribution rate class they are assigned.
- The net metering charge was removed to encourage residents to generate their own energy and support the City of Ottawa's Energy & Emissions Plan.

Specialized Distribution Rates for DERs – Current Approach

Context	***Hydro One's DGen Rate Class***
Connection Cost Responsibility	The DGen rate class, composed of delivery and regulatory components, is reserved for generation facilities greater than 10 kW connected to the distribution system.
Base Distribution Rates for FTM Generation	In the OEB proceeding EB-2005-0528, the OEB directed Hydro One to come forward with an updated rate design proposal for distributed generators that: • reflects the cost of serving the proposed new rate classification; and • considers the benefits that distributed generators provide. The load profile for this class is based on the consumption distributed generators require as station service when the active generators are not operating.
Base Distribution Rates for FTM Energy Storage	
Specialized Distribution Delivery Rates for DERs	EB-2007-0681, Exhibit A, Schedule 1, pg. 4 of 5; EB-2007-0681, Exhibit G2, Tab 1, Schedule 1, pg. 4 of 20
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Specialized Distribution Rates for DERs – Current Approach

Context	The following slides provide summary breakdown of the delivery and regulatory components of Hydro One's DGen rate class. Notably, a distribution rate for the use of the wires and service of connection is not identified within Hydro One's DGen rate class.
Connection Cost Responsibility	***Hydro One's DGen Delivery Components***
Base Distribution Rates for FTM Generation	• **Service Charge** • These are costs defined as meter-related, billing and collection costs. Hydro One notes that metering and settlement related costs associated with processing metering information, and the ongoing management of embedded generators accounts are allocated to the DGen rate class in alignment with principles of cost causality.
Base Distribution Rates for FTM Energy Storage	• **Distribution Volumetric Rate (coupled with a rate adder)** • Cost of commodity consumed plus the Customer Supplied Transformer Allowance (CSTA) adder. The CSTA adder was introduced to offset the projected cost of the CSTA credit, which is available to Hydro One customers as an equivalent to the cost of transformation in the rates if they provide their own transformation. These costs are recovered via the GSd, UGd, AUGd, AGSd, and DGen rate classes.
Specialized Distribution Delivery Rates for DERs	• **Rate Riders** • Rate riders were developed to recover the costs of the regulatory assets. The intent of these rate riders is to recover the costs of DVAs for acquired service areas and legacy customers; credits owed to former customers, including disposing of balance in account 1580 Capacity Based Recovery (CBR) Class B sub-account; GA balances for customers who transitioned between Class A and B during the balance
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Hydro One's DGen Delivery Components (Cont'd)

- **Retail Transmission Rate - Network Service Rate**
  - For energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the Ontario Energy Board.
  - For interval-metered customers: the peak demand from 7 a.m. to 7 p.m. (local time) on IESO business days in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the OEB.
  - For non-interval-metered demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the OEB.
- **Retail Transmission Rate - Line and Transformation Connection Service Rate**
  - For energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the OEB.
  - For all demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the OEB.
  - For customers with load displacement generation above 1 MW, or 2 MW for renewable generation, installed after October 1998, RTSR connection is billed at the gross demand level.

Specialized Distribution Rates for DERs – Current Approach

Context	***Hydro One's DGen Regulatory Components***
Connection Cost Responsibility	**i) Wholesale Market Service Rate (WMS) - not including CBR, ii) Capacity Based Recovery (CBR) - Applicable for Class B Customers, iii) Rural or Remote Electricity Rate Protection Charge (RRRP)**
Base Distribution Rates for FTM Generation	• The Wholesale Market Service Rate and the Rural or Remote Electricity Rate Protection Charge are applied solely to non-Wholesale Market Participants. For Class A customers, distributors shall bill the actual CBDR costs to Class A customers in proportion to their contribution to peak. These rates pertain to the IESO's defined point of sale; consequently, appropriate loss factors as approved by the OEB must be applied to the customers' metered energy.
Base Distribution Rates for FTM Energy Storage	**Standard Supply Service - Administrative Charge (if applicable)**
Specialized Distribution Delivery Rates for DERs	• If electricity is purchased directly from a customer's local utility, the customer pays an administrative fee to the utility to cover these costs. This charge is the same for all utilities in the province, set by the OEB.
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Specialized Distribution Rates for DERs – Current Approach

Context	***Alectra – Brampton's DGen Rate Class***
Connection Cost Responsibility	Alectra's DGen rate class is inherited from Hydro One Brampton Networks Inc., which it acquired following the amalgamation of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, and PowerStream Inc. in 2017 (referred to as LDC Co. prior to its renaming to Alectra). • In the OEB Decision and Order, the OEB ordered that the rate orders of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, PowerStream Inc. and Hydro One Brampton Networks Inc. be transferred to LDC Co. The delivery and regulatory components of Alecta's DGen rate class are largely identical to Hydro One's with few differences: • Addition of a low voltage service rate; • Exclusion of the distribution volumetric rate component; and • Variances in rate riders. These charges exclude any costs related to system operation. EB-2016-0025, EB-2016-0360
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Specialized Distribution Rates for DERs – Current Approach

Context	***microFIT Admin/Metering Charges***
Connection Cost Responsibility	The microFIT Program, launched in 2009 and received applications through 2017, let homeowners and other eligible participants develop renewable electricity projects of up to 10 kW and earn a guaranteed price over a 20-year term for power supplied to Ontario's grid.
Base Distribution Rates for FTM Generation	Distribution rate treatment for microFIT generators (which are distribution-connected generators) resulted from the proceeding that the OEB initiated on September 21, 2009, on its own motion in order to determine:
Base Distribution Rates for FTM Energy Storage	"a just and reasonable rate to be charged by an electricity distributor for the recovery of costs associated with an embedded generator account having a nameplate capacity of 10 kW or less […] that meets the eligibility requirement of the OPA's microFIT program."
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Specialized Distribution Rates for DERs – Current Approach

Context	The OEB's decision in EB-2009-0326 resulted in nine cost elements that comprise the microFIT charge, all of which relate to administrative activities and exclude any costs related to system operation: • Customer Premises - Operation Labour (Account 5070) • Customer Premises - Materials and Expenses (Account 5075) • Meter Expenses (Account 5065) • Maintenance of Meters (Account 5175) • Meter Reading Expense (Account 5310) • Customer Billing (Account 5315) • Amortization Expense – General Plant assigned to Meters • Administration and General expenses allocated to Operating and Maintenance expenses for meters • Allocated PILS (only general plant assigned to meters)
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Delivery Rates for BTM Resources	The OEB determined that those costs should be recovered solely through a fixed monthly service charge and that a single provincewide charge should be established for all distributors at the outset. The provincewide charge of $5.25 per month was established on the basis of the customer weighted average of nine specific cost elements (above) using data from 62 distributors.
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On the Issue of Grid Services	The OEB reviews the microFIT charge annually to ensure it continues to reflect actual costs. As part of its annual review of the microFIT charge for 2025, the OEB updated the charge to $5.00 per month in accordance with the established methodology. Distributors may request a distributor-specific microFIT charge in their cost-of-service applications, provided they can show their costs result in a materially different rate than the provincewide charge.

Specialized Distribution Rates for DERs – Current Thinking

Context	**Observations, updates and discussion questions:**
Connection Cost Responsibility	The commonality among current specialized distribution rates for direct-connected generation is that they account for the cost recovery associated with energy settlements (i.e., processing metering information) and administrative costs (i.e., account management and billing) for embedded retail generators. These charges exclude any costs related to system operation.
Base Distribution Rates for FTM Generation	The OEB's initial assessment is that the current rates are appropriate within their specific context, despite not being applicable to transmission-connected electricity resources.
Base Distribution Rates for FTM Energy Storage	Looking ahead, there may be an opportunity for the OEB to provide guidance to promote greater consistency in the development of specialized DER rates, particularly as the demand for such rates grows.
Specialized Distribution Delivery Rates for DERs	The OEB has done this in the past, when it established a provincewide fixed monthly service charge for microFIT generators (which are distribution-connected generators) based on nine cost elements specified by the OEB. The OEB reviews the microFIT charge annually.
Delivery Rates for BTM Resources	*In the event of greater deployment of DERs across Ontario's distribution systems, should the OEB consider opportunities to facilitate consistency in how specialized rates for DERs are developed and applied by Ontario's electricity distributors?*
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Delivery Rates for BTM Resources – Current Approach

Context	*The following section describes delivery rates for behind-the-customer meter (BTM) DERs, including RTSRs, standby rates and bypass compensation.*
Connection Cost Responsibility	**Retail Service Transmission Rates (RTSRs)**
Base Distribution Rates for FTM Generation	RTSRs are charges that electricity distributors apply to end-use customers to recover the costs of wholesale transmission line connection, transformation connection and network service charges that the distributors owe to transmitters.
Base Distribution Rates for FTM Energy Storage	Transmitter revenue requirements are recovered through OEB-approved Uniform Transmission Rates (UTRs), which are charged to all wholesale market participants, including electricity distributors. Electricity distributors allocate the UTRs that have been charged to them to their distribution customers in the form of RTSRs. Distributors remit the RTSR payments that they collect from their customers to the IESO, who then disburses those payments to Ontario's rate-regulated transmitters according to revenue disbursement allocators established by the OEB through UTR Rate Orders.
Specialized Distribution Delivery Rates for DERs	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.
Delivery Rates for BTM Resources	Under net load billing, the charges for a transmission customer are based on the load that the customer draws from the transmission system. Under gross load billing, the charges for a transmission customer are also based on the load that the customer draws from the transmission system, *plus* the load supplied by any behind-the-meter or "embedded" generation.
Demand-Side Resources	Through its Decision in Ontario's original UTR proceeding (RP-1999-0044), the OEB determined that net load billing shall apply to Network Service Charges. In contrast, the OEB determined that gross load billing shall apply to Line Connection Service and Transformation Connection Service charges (for load customers who connect embedded generation after October 30, 1998).
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Delivery Rates for BTM Resources – Current Approach

Context	The OEB also established a gross load billing threshold of greater than 1 MW for non-renewable generating units and greater than 2 MW for renewable generating units for the transformation and connection rate pools paid by transmission customers. That is, transmission load customers with behind-the-meter renewable generating units that are below 2 MW are billed on a net load basis for Connection Service and Transformation connection Service charges (or below 1 MW in the case of non-renewable generating units), while those with renewable generating units above 2MW are billed on a gross load basis. Since January 1, 2013, the OEB-approved Rate Order for Hydro One Networks Inc. (distribution) has stated that the monthly billing determinant for the RTSR Line and Transformation Connection Service rates for distribution customers with load displacement generation above 1 MW, or 2 MW for renewable generation, installed after October 1998, is billed at the gross demand level. For Hydro One Networks Inc.'s Sub Transmission (ST) rate class, the OEB-approved Rate Order states that customers with load displacement generation at 1 MW or above, or 2 MW or above for renewable generation, installed after October 1998, ST volumetric charges are billed at the gross demand level. While there appears to be alignment between how Hydro One Networks Inc. load customers with embedded generation are billed RTSRs and the way transmission load customers with embedded generation are billed for transmission rates, it does not appear to be the case with all distributors in Ontario. The OEB**'s** review of a sample of OEB-approved distribution rate orders suggests that not all electricity distributor rate schedules distinguish between net load billing and gross load billing with respect to RTSRs for distribution customers that have behind-the-meter DERs. There might be an opportunity to achieve greater consistency in how transmission delivery rates (RTSRs) are applied to distribution load customers with behind-the-meter generation, in terms of distinguishing between net load and gross load billing. This could provide added predictability for load customers with behind-the-meter DERs. It could also enhance the existing alignment between Ontario's distribution and transmission rates frameworks for behind-the-meter resources.
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Standby Rates

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 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 (LDG) generation and that require standby service from their electricity distributor.

Existing standby rates for LDG were declared interim by the OEB in 2006 through a generic proceeding (RP-2005-0020, EB-2005-0529). In 2011, as part of the OEB's report on cost allocation review (EB-2010-0219), the OEB invited electricity distributors to apply to have their rates declared final as part of their cost of service applications. While some distributors did apply and received approval for finalization, most electricity distributors with standby rates are still applying them on an interim basis.

The OEB held a consultation in 2023 (EB-2023-0278) to consider standby rates given the passage of time, since standby rates were first declared interim in 2006. The OEB concluded in 2024 that "based on feedback in this consultation and on the evolving nature of DERs and other behind-the-meter alternatives, the OEB is not prepared to impose or recommend a default approach to pricing LDG at this time." The OEB added that "cost causation should remain a key consideration in development of any standby rate proposal."

Standby rates currently exist at 10 electricity distribution utilities in Ontario. Of those, standby rates are interim at six utilities.

Delivery Rates for BTM Resources – Current Approach

Context	Toronto Hydro recently eliminated its standby rate, as part of an OEB-approved settlement agreement with the Parties in its 2025-2029 revenue requirement application proceeding (EB-2023-0195). In the settlement agreement, the Parties agreed that the elimination of Toronto Hydro's Standby Rate "is without prejudice to any Party arguing for or against the creation of such a rate in the future." Toronto Hydro's evidence to the OEB outlined various considerations related to its standby rate, including cost recovery, fair cost allocation and alignment with public policy: "Toronto Hydro notes that technology and customers' usage of [DERs] have significantly evolved since the standby rates concept was introduced. Further, there are an increasing number of public policy imperatives (e.g., climate action, resiliency, affordability, flexibility) driving the sector to support the adoption of DERs. Standby rates, which operate to increase the amount paid by customers who utilize DERs, seem to conflict with those public policy imperatives. At the same time, regulatory policy must balance those imperatives with the interests of fair cost allocation among customers and full cost recovery for utilities." Hydro Ottawa recently applied to the OEB to update and finalize its standby rate (EB-2024-0115). Hydro Ottawa customers with LDG equal to or greater than 500 kW and who require standby service are subject to both a standby monthly fixed service charge and volumetric charge. The fixed service charge is designed to recover the incremental cost of monitoring, billing and administration related to providing standby services and the distribution volumetric standby charge is to recover the cost of maintaining standby facilities at any time. Hydro Ottawa customers can elect to contract standby reserve capacity at the full nameplate value of its LDG, or at a lesser amount if it intends to shed load when the generation is not available. "Backup Overrun Adjustments" are applied if the customer is forced to use standby capacity that is not contracted. Hydro Ottawa reserves the right to impose a contract if a customer fails to meet its obligations and uses Hydro Ottawa for backup service periodically.
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Delivery Rates for BTM Resources – Current Approach

Context	The OEB notes that standby rates are applied to distribution-connected customers with LDG in Ontario, but not to transmission-connected customers that have behind-the-meter resources. While this is a difference between Ontario's transmission and distribution delivery rates frameworks, the OEB proposes that the difference is appropriate, reflecting the specific circumstances of electricity distributors. The OEB further notes that OEB-approved standby rates reflect a service that electricity distributors offer to their customers who want to use it. While most standby rates are interim and distributor-specific, the OEB has chosen not to impose or recommend a default approach to pricing LDG. Instead, the OEB has stated that "electricity distributors are in the best position to know their system and cost causation and are encouraged to understand their customer needs." Looking ahead, the OEB has stated that "if a distributor determines that a standby rate is appropriate, it should propose a design that best fits the circumstances." In such cases, "future OEB Commissioner panels will decide on applications for new standby rates based on evidence in the proceeding and the application of sound ratemaking principles." The OEB has encouraged distributors to work with their customers in developing any standby rate and has noted that, in some circumstances, the need for a standby rate might not be warranted. The OEB notes that as distributors propose to finalize their standby rates over time, there will be more opportunities to review best practices, apply lessons learned and facilitate the ongoing effectiveness of DER delivery rates in Ontario.
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Bypass Compensation

Section 3.5 of the DSC provides that an electricity distributor must require bypass compensation from a customer with a non-coincident peak demand of 5 MW or more if any of the following conditions apply:

(a) the customer disconnects its load facility from the distributor's distribution system and connects that facility to a generation facility or to another load facility that is not owned by the distributor such that the distributor will no longer receive rate revenues in relation to that disconnected facility; or

(b) the customer, while retaining its connection to the distributor's distribution system, also connects its load facility to a generation facility or to another load facility that is not owned by the distributor such that the customer reduces its load served directly by the distributor's distribution system, and the distributor's rate revenues in relation to that facility will be reduced.

The DSC also sets out the circumstances in which bypass compensation may not be applied, including "any reduction in a customer's existing load served by the distributor's distribution system that the customer has demonstrated to the reasonable satisfaction of the distributor (such as by means of an energy study or audit) has resulted from embedded renewable generation, energy conservation, energy efficiency or load management activities."

This is consistent with the bypass compensation rules that apply to transmitters: analogous provisions in section 11.2 of the TSC are analogous to those found in section 3.5 of the DSC.

Delivery Rates for BTM Resources – Current Approach

Context	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 to the TSC in 2005 (RP-2004-0220).
Connection Cost Responsibility	The OEB provided reasons for the exemptions in a 2004 Policy Decision: "The Board is of the view that reductions in load, attributable to energy conservation, energy efficiency, and load management, should not be considered system bypass, under any circumstances. The promotion of energy efficiency and conservation is one of the objectives of the Act and is particularly important at a time when Ontario faces a tight supply of electricity. There appears to be consensus that the Ontario electricity market requires increased demand response and conservation measures, and many initiatives are underway to facilitate achievement of that goal. The Board is of the view that it is particularly important to ensure that the Code does not contain or create any barriers or disincentives for energy efficiency and conservation initiatives." - RP-2002-0120, OEB Phase 1 Policy Decision with Reasons, June 8, 2004 In 2005, the OEB provided additional context for the exemptions in its synopsis of changes to the TSC: "Practices that discourage these initiatives, such as a transmitter imposing a minimum payment obligation to cover present loads, will now be prohibited. Allowing such practices would require a customer to pay the same minimum amount even if, for example, they were able to cut their demand in half. This would constitute a penalty for conserving energy which is inconsistent with the societal goal to create a 'culture of conservation' in Ontario." - RP-2004-0220, OEB Synopsis of Changes to the Transmission System Code, July 25, 2005
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Delivery Rates for BTM Resources – Current Thinking

Context	**Observations, updates and discussion questions**
Connection Cost Responsibility	***Standby Rates***
Base Distribution Rates for FTM Generation	Standby rates currently exist at 10 electricity distribution utilities in Ontario, mostly 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.
Base Distribution Rates for FTM Energy Storage	*As distributors propose to finalize their standby rates over time, should the OEB review best standby rates practices and applying lessons learned to facilitate the ongoing effectiveness of DER delivery rates in Ontario?*
Specialized Distribution Delivery Rates for DERs	***Bypass Compensation***
Delivery Rates for BTM Resources	The DSC sets out the circumstances in which an electricity distributor must require bypass compensation from a customer. The DSC also sets out the circumstances in which bypass compensation may not be applied. This is consistent with the bypass compensation rules that apply to transmitters per the Transmission System Code.
Demand-Side Resources	*Should the OEB review its policy related to bypass compensation exemptions given the passage of time since the policy was first established and given the rapidly evolving context for DER deployment in Ontario?*
On the Issue of Grid Services	• *Areas for focus might include evaluating the continued suitability and scope of existing bypass compensation exemptions (e.g. should exemptions be extended to also include non-renewable DERs?), and opportunities for continued harmonization between applicable provisions in the TSC and DSC.*

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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 Ontario's Uniform Transmission Rates. However, it does not appear that all distributors in Ontario distinguish between net load billing and gross load billing with respect to Retail Transmission Service Rates for distribution customers that have behind-the-meter DERs.

Should the OEB review opportunities to achieve greater consistency in how transmission delivery rates (Retail Transmission Service Rates) are applied to distribution load customers with behind-the-meter generation, in terms of distinguishing between net load and gross load billing?

- *This could provide added predictability for load customers with behind-the-meter DERs. It could also enhance the existing alignment between Ontario's distribution and transmission rates frameworks for behind-the-meter resources.*

Demand-Side Resources

Context	*This section situates loads that host dynamic electric load-modifying technologies or practices falls within the overall subject of delivery rates for load customers.*
Connection Cost Responsibility	As indicated previously, for the purposes of this report, DERs include electricity generating technologies, storage technologies or dynamic electric load-modifying technologies or practices hosted by a distribution customer.
Base Distribution Rates for FTM Generation	This report has explicitly addressed delivery rate treatment for front-of-the-meter DERs, including generation and storage, as well as load displacement generation in the context of behind-the-meter DERs. The report has also described connection cost responsibility as it applies to generation and loads.
Base Distribution Rates for FTM Energy Storage	The OEB proposes that the subject of delivery rates for loads that host dynamic electric load-modifying technologies or practices falls within the overall subject of delivery rates for load customers. Accordingly, the OEB has not proposed any specific areas for potential reform or further exploration in relation to load modifying DERs other than electricity storage. Specifically, the OEB has proposed a potential reform to the base rate treatment of front-of-the-meter storage earlier in this report. The OEB has also identified potential policy opportunities to support storage in relation to cost responsibility for distribution system expansion and exemption from bypass compensation.
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This section addresses item #11 of the IEP implementation directive, which specifically refers to demand/delivery charges for resources that provide grid services.

Item #11 of the IEP implementation directive to the OEB references "demand/delivery charges for resources *that provide grid services*" (emphasis added). The term "grid services" is not defined in the IEP implementation directive, but it appears in the government's 2025 IEP, most often in the IEP's discussion of "Ontario's Future Electricity Grid" and the role of DERs (Chapter 4, see pages 87-88). The IEP addresses the grid services provided by DERs in the contexts of planning, participation, compensation and procurement.

In the case of planning, the IEP notes that "there is significant opportunity to guide DER investment to where it is most cost-effective and beneficial to local and system-wide needs – helping to relieve constraints, defer costly infrastructure, and improve overall efficiency." The IEP states that "Ontario's energy system must evolve to […] use DER as reliable, low-cost providers of grid services".

In the case of participation, the IEP makes various references to expanding opportunities for DERs, for mobilizing DER providers and investors and enabling broader eligibility for DERs in IESO procurements and programs, and for expanding eligibility for net metering.

On the Issue of Grid Services (Cont'd)

Context	In the case of compensation and procurement, the IEP states that Ontario's energy system must evolve to "monetize DER fairly, ensuring customers receive compensation that reflects the value their resources contribute to the grid," and that Ontario is taking actions to expand "near-term opportunities for demand response, capacity, ancillary services and storage; including DER aggregation in future competitive procurements." The IEP specifically notes that "DER aggregations can provide opportunities for smaller DER to provide and be compensated for grid services." A variety of the items in the IEP implementation directive to the OEB require actions from the OEB related to DER planning, participation, procurement and compensation. • Item #14 directs the OEB to "ensure planning processes adequately consider cost-effective DER deployment." • Items #15 through #17 will facilitate DER participation by requiring the OEB to continue to update DER connection processes, to enhance data sharing practices between the IESO, electricity distributors and DER providers, and to define a roadmap for the potential development and implementation of Distribution System Operator capabilities. • Item #13 requires the OEB to explore further opportunities to enable electricity distributors to recover investments in DER and non-wires solutions.
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On the Issue of Grid Services (Cont'd)

Context	The OEB's report to the Minister of Energy and Mines on IEP implementation directive item #11 will address DER compensation and procurement as well as delivery rates.
Connection Cost Responsibility	Delivery rates for DERs relate to the costs of incorporating DERs into distribution systems and to providing the distribution infrastructure and services that are required to deliver the grid services that DERs provide to customers.
Base Distribution Rates for FTM Generation	Relatedly but distinctly, the issues of DER procurement and compensation relate to acquiring and paying for the grid services that DERs provide.
Base Distribution Rates for FTM Energy Storage	The OEB proposes to consider delivery rates for DERs in the context of item #11 with focus on delivery rates that DER providers and/or other customers pay. This is consistent with the general basis for delivery rates in Ontario: delivery rates reflect the costs of providing delivery service. They are not derived based on the grid services or values that the entities who require the delivery service (such as generators and loads) provide to customers (such as energy, capacity and ancillary services). Those grid services or values are reflected instead in planning decisions related to DERs, in DER procurements and compensation, and in DER participation in procurements and programs, and in government policies.
Specialized Distribution Delivery Rates for DERs	
Delivery Rates for BTM Resources	Therefore, while the OEB will address DER delivery rates with a focus on the costs of providing delivery service to DER providers and to customers who use DER services, it will also address the complementary issues of procurement mechanisms for acquiring DERs and compensation mechanisms for remunerating DERs for the various grid services that they provide to customers. Together, the OEB's report to the Minister will address both costs and values related to DERs.
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