Ontario's Distributed Energy Resources (DER) Potential Study

Volume II: Methodology & Assumptions

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A. Pre-Assessment Methodology

A.1 Long List of Measures

The study team developed a comprehensive long list of DER measures and summarized market and performance data features for each measure. These features included measure operational parameters (defined in Table A-1: Operational Parameter Definitions), grid services offered by the measure (defined in Table A-2), and other technology-specific considerations (defined in Table A-3). A comprehensive overview of features by measure is included in **Appendix F - Measure Screening and Approach**.

Table A-1: Operational Parameter Definitions

Operational Parameter	Parameter Setting	Setting Definition
Enabling Device	Smart device/switch	Control functionality is enabled through an add-on smart device/switch.
	Embedded	Control functionality is embedded into the equipment.
Device Control Strategy	Direct Controlled	Utility/ISO has direct control over measure operation and requires opt-out request from the customer to avoid event participation.
	Scheduled	Reduce load for personal benefit (e.g. bill management) or in response to a price signal or other behavioural stimulus (e.g. time-of-use pricing, critical peak pricing, price alerts).
Dispatchable	Yes	Can respond to dispatch instructions within 5 minutes. Considers aggregate resources' ability to respond.
	No	DERs that are not controllable and/or cannot respond to dispatch instructions within 5 minutes.
Service Provision Pathway	Direct Participant	Resources that are able to directly participate in the market to provide grid services.
	Aggregate Participant	Resources that must go through an aggregated portfolio or a DER program to participate in providing grid services.
	Not in the Market/Other	Resources that are ineligible for service provision.
	Multiple Pathways	Resources that are able to directly participate in the market or join an aggregated portfolio of DERs to provide grid services.

Table A-2: Grid Service Definitions

Grid Service	Definition
Electricity – Inject	Ability to inject electricity into the grid.
Energy – Arbitrage	Ability to take advantage of a price difference over time.
Energy – Avoid Curtailment (i.e. SBG)	Ability to increase system load when called upon.
Capacity	Ability to provide firm capacity or curtailment hourly.
Operating Reserves	Ability to provide firm capacity or curtailment at 10- or 30-minutes dispatch.
Regulation Capacity	Ability to provide firm capacity or curtailment for short-term (with response times under 10 seconds) corrections.

Table A-3: Technology Considerations Definitions

Consideration	Definition
Technology Maturity	Degree of operational readiness and availability, categorized as emerging, commercially available, or mature.
Cost Enhancements Expected by End of Study	Expectation of cost reductions over the course of the study, categorized as “Yes”, “No”, or “Maybe”.
Performance Enhancements Expected by End of Study	Expectation of technology performance improvements over the course of the study, categorized as “Yes”, “No”, or “Maybe”.
Demonstrated Use in Ontario and/or other Markets	Whether measure has been used to provide grid services in Ontario or other markets, categorized as “Yes”, “No”, or “Limited”.

A.2 Measure Screening

Next, the study team vetted each measure in the DER long list against screening criteria (defined in Table A-4: Measure Screening Criteria Definitions). The screening criteria were designed to identify those DERs most likely to provide a meaningful contribution to Ontario’s electricity system over the ten-year study period. A comprehensive overview of screening by measure is included in **Appendix F - Measure Screening and Approach**.

Table A-4: Measure Screening Criteria Definitions

Measure Screening Criteria	Criteria Setting	Setting Definition
Alignment with System Needs and Characteristics	Low	Not able to provide many of the grid services required to meet system needs.
	Mid	Able to provide some grid services to meet some system needs.
	High	Well suited to provide a range of grid services to meet system needs.
Opportunity Size	Low	Small market size and limited growth within the study period.
	Mid	Medium market size, or small market size with moderate growth within the study period.
	High	Large market opportunity within the study period.
Potential to Deliver GHG Reductions	Low	Measures that may increase greenhouse gas emissions.
	Mid	Measures that have the potential to slightly contribute towards emissions reductions.
	High	Measures that have the potential to substantially decrease emissions.
Expected Customer Cost-Effectiveness	Low	Not expected to be cost-effective within the study period.
	Mid	Expected to be cost-effective within the study period.
	High	Expected to be very cost-effective within the study period.
Market Readiness	Low	The technology has limited availability and/or demonstrated use.

Measure Screening Criteria	Criteria Setting	Setting Definition
	Mid	The technology is available but has some factors that would limit its adoption in the market, such as higher costs, limited availability, etc.
	High	The technology is widely available and demonstrated.
Alignment with Customer Goals	Low	Measures do not meet customer needs and preferences, for example, do not reduce emissions, have the potential to increase customer bills and/or are a hassle for the customer's day-to-day operations.
	Mid	Measures generally align with customer needs and preferences, for example, energy efficiency and demand response measures.
	High	Measures align with customer needs and preferences for resiliency, bill reductions, etc.

A.3 Measure Selection

Based on the measure screening exercise, the team recommended each measure either be included in the study or excluded (grouped by resource type, see Table A-5, Table A-6, and Table A-7). The pre-assessment and screening results – including the measure recommendations – was presented to stakeholders as part of the first study stakeholder session, held in September 2021. Considering the comments received from stakeholders, the study team and the IESO finalized the DER measure list, selecting the measures to be included in the study (see Volume I, section 3.4 Measure Selection).

Table A-5: DR Measure Selection

Measure	Include in Study?	Rationale
LDV Fleet EV Smart Chargers	Yes	EV smart chargers are expected to grow significantly as the share of EVs increases over the study period, while being cost-effective.
LDV Fleet EV Telematics	Yes	Over the study period, market readiness and opportunity size are expected to grow and deliver cost-effective services.
LDV Fleet Vehicle-to-Building/Grid (V2B/G)	Yes	V2B/G can provide valuable services to the grid. Over the study period, market readiness and opportunity size are expected to grow and deliver cost-effective services.
MDV Fleet EV Smart Chargers	Yes	EV smart chargers are expected to grow significantly as the share of EVs increase over the study period, while being cost-effective.
MDV Fleet Vehicle-to-Building/Grid (V2B/G)	Yes	V2B/G can provide valuable services to the grid. Over the study period, market readiness and opportunity size are expected to grow and deliver cost-effective services.
HDV Fleet EV Smart Chargers	Yes	EV smart chargers are expected to grow significantly as the share of EVs increase over the study period, while being cost-effective.
HDV Fleet Vehicle-to-Building/Grid (V2B/G)	Yes	V2B/G can provide valuable services to the grid. Over the study period, market readiness and opportunity size are expected to grow and deliver cost-effective services.
Buses: EV Smart Charging	Yes	EV smart chargers are expected to grow significantly as the share of EVs increase over the study period, while being cost-effective.

Measure	Include in Study?	Rationale
Buses: Vehicle-to-Building/Grid (V2B/G)	Yes	V2B/G can provide valuable services to the grid. Over the study period, market readiness and opportunity size are expected to grow and deliver cost-effective services.
Large Commercial HVAC Control	Yes	Commercial curtailment, including HVAC, is amongst the most cost-effective DER measures. It also has a large potential impact.
Small Commercial Smart Thermostat	Yes	Smart thermostat control is a staple of DER, with high opportunities and cost-effectiveness.
Lighting Controls	Yes	Commercial curtailment, including lighting, is amongst the most cost-effective DER measures and has high opportunities.
District Cooling/Heating Flexibility	Yes	Limited ability to contribute to system needs and limited market opportunities, however the district geothermal/geoexchange market is growing in Ontario, and communities have expressed an interest in pursuing these systems.
Other Commercial Flexibility	Yes	Commercial curtailment, including process curtailment, is amongst the most cost-effective DER measures and has large opportunities.
Irrigation Pump Controls	Yes	Offers mid-level benefits, but limited market opportunities.
Refrigeration Controls	Yes	Cost-effective measure, but potential is mainly limited to the food sale and warehouse segments.
Greenhouses: Grow Lights	Yes	Growing market and expected to be cost-effective.
Commercial HVAC Thermal Storage	Yes	Thermal storage has been around for decades and is expected to deliver cost-effective savings in the commercial sector.
Thermal Storage for Refrigeration Applications	Yes	Thermal storage has been around for decades and is expected to deliver cost-effective savings in the commercial sector.
Large Commercial Dual-Fuel Water Heating	Yes	Limited market opportunity and GHG reductions, however, could provide an opportunity to reduce peak through fuel shifting.
Large Commercial Hot Water	Yes	Commercial curtailment, including hot water, is amongst the most cost-effective DER measures and with large opportunities.
Small Commercial Hot Water	Yes	Electric water heaters can provide high value services to the grid, while being cost-effectiveness.
Small Commercial ASHP/DMSHP Smart Thermostat	Yes	Smart thermostat control is a staple of DER, with high opportunities and cost-effectiveness.
Industrial Flexibility	Yes	Industrial curtailment is amongst the most cost-effective DER measures and with large opportunities.
Residential AC Thermostat	Yes	Smart thermostat control is a staple DR, with high opportunities and cost-effectiveness.
Dual-Fuel Space Heating Smart Thermostat/Switch	Yes	Limited market opportunity and GHG reductions, however, could provide an opportunity to reduce peak through fuel shifting.
Other Behavioral-based Residential Flexibility	Yes	Although difficult to quantify, behavior-based residential curtailment is generally highly cost-effective.
Smart EV Chargers	Yes	EV smart chargers are expected to grow significantly as the share of EVs increases over the study period, while being cost-effective.
Passenger EV Telematics	Yes	Over the study period, market readiness and opportunity size are expected to grow and deliver cost-effective services.

Measure	Include in Study?	Rationale
Vehicle-to-Building/Grid (V2B/G)	Yes	V2B/G can provide valuable services to the grid. Over the study period, market readiness and opportunity size are expected to grow and deliver cost-effective services.
Smart Clothes Dryer	Yes	Often cost-effective, and has good potential in the single-family segment.
Thermal Storage for Heating	Yes	Residential thermal storage has large opportunity and is market ready. However, cost-effectiveness is not always achieved.
Thermal Storage for Cooling	Yes	Residential thermal storage has large opportunity and is market ready. However, cost-effectiveness is not always achieved.
Thermal Storage and Heat Pump	Yes	Residential thermal storage has large opportunity and is market ready. However, cost-effectiveness is not always achieved.
Electric Resistance Water Heaters Smart Switch	Yes	Electric water heaters can provide high value services to the grid, while being cost-effectiveness.
Heat Pump Water Heater Smart Switch	Yes	Electric water heaters can provide high value services to the grid, while being cost-effectiveness. Heat Pump water heater penetration is modelled to grow over the duration of the study.
Smart Electric Resistance Water Heaters	Yes	Electric water heaters can provide high value services to the grid, while being cost-effective.
Smart Heat Pump Water Heaters	Yes	Electric water heaters can provide high value services to the grid, while being cost-effectiveness. Heat Pump water heater penetration is expected to grow over the duration of the study.
ASHP/DMSHP Smart Thermostat	Yes	Smart thermostat control is a staple of DER, with high opportunities and cost-effectiveness.
Res. Pool Pumps	Yes	Limited ability to contribute to system needs, but usually highly cost-effective.
Residential Electric Furnace Smart Thermostat	Yes	In BAU+ and Accelerated Scenarios, there is a shift to a winter peak. Electric heating curtailment can contribute to system needs in these scenarios.
Residential Baseboard Smart Thermostat	Yes	In BAU+ and Accelerated Scenarios, there is a shift to a winter peak. Electric heating curtailment can contribute to system needs in these scenarios.
LDV Fleet EV Charger Smart Switch	No	Prevalence of smart charging as well as in-vehicle charging capabilities likely to limit market for “dumb” EV chargers.
Pool Heating	No	Limited market opportunity given the small market size.
Pool Pumps	No	Limited ability to contribute to system needs.
Spa/Hot Tubs	No	Offers mid-level benefits, with low market opportunities.
Small Commercial Dual-Fuel Water Heating	No	Limited market opportunity and GHG reductions.
Small Commercial GSHP Smart Thermostat	No	Limited market opportunity given the small market size. Will be blended with ASHP.

Measure	Include in Study?	Rationale
Residential GSHP Smart Thermostat	No	Limited market opportunity given the small market size. Will be blended with ASHP.
Residential EV Charger Smart Switch	No	Prevalence of smart charging as well as in-vehicle charging capabilities likely to limit market for “dumb” EV chargers.
Residential Electric Resistance Pool Heaters	No	Limited market opportunity given the small market size.
Residential Heat Pump Pool Heaters	No	Limited market opportunity given the small market size.
Residential Hot Tub/Spa	No	Limited ability to contribute to system needs and low opportunity size.
Residential Clothes Dryer Smart Switch	No	Measure typically not found to be cost-effective.
Residential Dehumidifiers Smart Switch	No	Measure typically not found to be cost-effective.
Residential Dishwasher / Clothes Washer Smart Switch	No	Measure typically not found to be cost-effective.
Residential Fridge/Freezer Smart Switch	No	Measure typically not found to be cost-effective.
Residential Smart Dishwasher / Clothes Washer	No	Measure typically not found to be cost-effective.
Residential Smart Fridge/Freezer	No	Measure typically not found to be cost-effective.
Residential Dual-Fuel Water Heating	No	Limited market opportunity and GHG reductions.

Table A-6: BTM Resource Measure Selection

Measure	Include in Study?	Rationale
Non-Residential Back-up Generation	Yes	Backup generation is an available resource that can be tapped into with minimal costs.
Non-Residential BTM Solar with Smart Inverters	Yes	Solar is a market ready technology. When paired with flexible loads and batteries, it can provide significant flexibility and align with system needs. Solar is expected to be cost-effective for both the customer and the system.
Non-Residential BTM Battery Storage	Yes	BTM standalone storage is a flexible resource for grid services, with expected cost reductions, leading to cost-efficient deployment over the study period.
Residential BTM Solar with Smart Inverters	Yes	Solar is a market ready technology. When paired with flexible loads and batteries, it can provide significant flexibility and align with system needs. Solar is expected to be cost-effective for both the customer and the system.
Residential BTM Battery Storage	Yes	BTM standalone storage is a flexible resource for grid services, with expected cost reductions, leading to cost-efficient deployment over the study period.

Measure	Include in Study?	Rationale
Non-Residential CHP	No	Limited future opportunities expected to emerge given the limited potential for grid service provisions, GHG savings and cost-effectiveness relative to other measures.
Non-Residential Hydrogen Fuel Cell	No	Market readiness and cost-effectiveness is limited.
Non-Residential Biomass/Biogas	No	Offers mid-level benefits, with low market opportunities & low cost-effectiveness.
Non-Residential Short-duration Storage (flywheel, Capacitor Bank, etc.)	No	Expensive technology and limited applicability (regulation).
Residential Other Micro Generation (Micro Wind, Micro Hydro, Micro CHP, etc.)	No	Limited market opportunity given the small market size.
Non-Residential Natural Gas Fuel Cell	No	Low GHG reduction compared to other DER.

Table A-7: FTM Resource Measure Selection

Measure	Include in Study?	Rationale
FTM Solar	Yes	Solar is a market ready technology that can provide energy and some capacity at a relatively low cost.
FTM Small-scale Hydro	Yes	Existing small hydro resources can provide cost-effective grid services.
FTM Battery Storage	Yes	FTM standalone storage is a flexible resource for grid services, with expected cost reductions, leading to cost-efficient deployment over the study period.
FTM Biomass/Biogas	No	Limited expected cost-effectiveness and market opportunities given the competition for biomass feedstock.
FTM Small-scale Wind	No	Limited market opportunity given the small market size.
Compressed Air Energy Storage (CAES)	No	Typically deployed as a transmission connected asset to leverage economies for scale.
Power-to-Gas (Hydrogen)	No	Market readiness and cost-effectiveness limited over the study period.
Flywheel	No	Limited ability to contribute to system needs and minimal cost-effectiveness compared to other storage measures.
Electrothermal Storage	No	Typically deployed in larger transmission-connected set-ups to leverage economies for scale.

B. Technical Potential Methodology

Technical potential quantifies the theoretical maximum potential for DERs in Ontario to provide different grid services over the study period, regardless of cost-effectiveness or customer adoption. It is a theoretical representation of the projected pool of potential DER opportunities from which the Economic and Achievable potentials are calculated. The technical potential was largely used to establish the maximum market size for each DER measure. It was calculated by combining the market size for each measure with a measure's unit impact, considering technical and operational constraints.

The following sub-sections describe the approach employed in the study to calculate the technical potential for DERs in Ontario. Details on the approach and assumptions for market characterization for each measure are presented in Appendix F - Measure Screening and Approach.

B.1 Market Characterization

Market characterization refers to the process used to define and quantify the technical market size for each measure over the study period. The technical market size is then combined with the individual DER specifications (i.e. nameplate capacity, peak coincidence factors, capacity factors etc.) to assess the technical potential of each measure. The approach used to define the market size depends on the type of measure, as highlighted in the following sections.

B.1.1 Demand Response Measures

For DR measures, the maximum market size is defined as the full participation of the applicable equipment stock (e.g. the number of air conditioning units) in all services they can contribute to. Current market penetration data was primarily based on data from the IESO's 2021 Annual Planning Outlook, Residential End Use Survey (REUS) and Commercial End Use Survey (CEUS) and complemented with other market data and resources.

The approach to estimating market growth over the study was varied by measure, but typically followed population/segment growth for established technologies (e.g. hot water systems), forecasted adoption from the Annual Planning Outlook for high-growth areas (e.g. EV or HP uptake[1]), or third-party market intelligence for emerging technologies (e.g. V2B/G, EV telematics).

B.1.2 BTM and FTM Measures

For BTM and FTM DG and storage measures, market size is defined as the technology-specific physical, technical and/or market constraints that would limit potential opportunities for a given measure across Ontario. For example, the market for BTM solar resources is based on number of buildings with a rooftop suitable for solar deployment. Similar constraining factors were considered for other resources to develop a reasonable estimate of the maximum theoretical potential for deployment in Ontario.

[1] The technical potential of high-growth measures is influenced by vehicle and building electrification, which is varied by scenario. See section E.1 Electrification for more details.

The team leveraged the 2018 IESO-commissioned Solar Achievable Potential Study (APS) to assess the technical potential for BTM solar. For other DG and storage resources, the team employed professional judgement to develop appropriate market sizing metrics. Market growth for DR/DG measures was generally based on the assumed segment/population growth.

INDUSTRIAL DR AND FTM MARKET SIZING

Given their unique nature, a distinct approach was used for sizing for industrial DR and FTM markets:

- **Industrial:** Due to limited industrial sector data on end-use load breakdown, the study team used a proxy measure sizing approach to size industrial DR. Specifically, the sector's load was segmented into incremental 1 MW peak blocks; which can represent either a single 1 MW DR participant or multiple DR participants that collectively have a 1 MW peak capacity. With each unit of DR dispatched assumed to be 1 MW, the market was then sized based on the total peak consumption of the sector. In general, the industrial sector load profiles are extremely flat, and thus no attempt was made to identify load shifting opportunities. Instead, it was assumed that industrial DR measures would focus more on curtailing loads during peak events, primarily through temporary shut-downs of appropriate equipment or processes.

- **FTM:** The study assumes that the technical potential for FTM resources is determined by the capacity required to fully displace the marginal generating resource in Ontario (i.e. natural gas fired generation), while also accounting for any physical constraints associated with specific measures. 10,000 MW of natural gas capacity are assumed to be deployed in Ontario throughout the study period. Based on an assumed typical measure size (nameplate capacity) and an initial assumption on effective capacity contribution for the FTM solar and storage resources, the market size was estimated as the number of systems that would be required to fully displace marginal natural gas generating capacity. This was considered to be a more reasonable assessment of the technical potential for these FTM resources, based on meeting the marginal capacity needs, as opposed to determining all feasible FTM solar and storage sites across the provinces, as was done for the small-scale hydro (where existing data was available).

The table below highlights a number of illustrative examples of the market sizing and growth approach for several key DR, DG and storage measures.

Table B-1: Illustrative Examples of Market Characterization Approach

Measure Name	Type	Technical Market Sizing Approach	Market Growth Approach
AC Smart Thermostats	**DR**	Number of residential buildings with a central AC system.	Rate of AC adoption.
LDV Fleet EV Smart Charging	**DR**	Forecasted number of light-duty fleet vehicles in Ontario.	Forecasted EV fleet adoption.
Smart Clothes Dryer	**DR**	Number of residential customers with an electric clothes dryer.	Rate of clothes dryer growth.
Residential BTM Solar	**DG**	Number of single-family homes with a rooftop suitable for solar deployment.	Rate of residential new construction.
Non-Residential BTM Storage	**Storage**	Number of commercial customers with suitable space for storage deployment.	Segment population growth.
FTM Solar	**DG**	Solar capacity needed to displace the marginal resource (i.e. natural gas) considering physical constraints.	None.

B.2 Measure Characterization (Technical)

Measure characterization refers to the process used to define key technical and operational characteristics for each measure to quantify its impact.[2]

The table below highlights a number of illustrative examples of the measure characterization approach used for a number of key DR, DG, and storage measures. Details on the approach and assumptions for market characterization for each measure are presented in in Appendix F - Measure Screening and Approach.

[2] Additional characterization of economic metrics for each measure is completed under Economic Potential.

Table B-2: Illustrative Examples of Measure Characterization Approach

Measure Name	Type	Measure Size (kW)	Baseline Load Profile	Service Capability[3]				Modified Load Profile (Capacity)
				E	C	OR	RC	
AC Smart Thermostats	DR	Sized to cooling and pumps and ventilation load. Varies by segment.	Cooling, pumps & ventilation load for each segment from APO.	✓	✓	✓		Called 4 hours max, with Precooling and rebound. Called not more than 15 times a year.
LDV Fleet EV Smart Charging	DR	Nameplate capacity of typical Level-2 EV Charger.	Average LDV non-residential EV load profile.	✓	✓	✓	✓	Curtail charging during peak hours. Provide up to 6 hours of curtailable load during the evening peak.
Smart Clothes Dryer	DR	Sized to maximum clothes dryer load.	Average clothes dryer load profile from APO.	✓	✓			100% of load curtailed during peak window.
Residential BTM Solar	DG	Maximum system size that can be theoretically deployed on the building's rooftop based on roof area and typical panel footprint.	Ontario-average solar generation profile (adapted to measure size).	✓	✓			Based on coincidence of generation with peak window.
Non-Residential BTM Storage	Storage	Sized to customer's peak load.	N/A	✓	✓	✓	✓	Sustained capacity reduction during peak hours.
FTM Solar	DG	10 MW solar farms. (See call-out box in section B.2.2)	Ontario-average solar generation profile (adapted to measure size).	✓	✓			Based on coincidence of generation with peak window.

B.2.1 Demand Response Measures

For demand response measures, the following steps are used to characterize the measure's impact:

- **Baseline load profile:** The hourly load profile for each measure in the absence of any DR event. The baseline loads used in the study are primarily based on the segment/end-use load characterization from the IESO's APO. For plug-loads / equipment and emerging end-uses (e.g. fleet charging), assumed load profiles were developed using Ontario-specific data where available or data from jurisdictions with similar characteristics (e.g. North East USA).

[3] E: Energy; C: Capacity; OR: Operating Reserves; RC: Regulation Capacity

- **Measure size (kW):** The maximum load size (e.g. size of the heating or cooling load, for heating and cooling measures) and/or the nameplate capacity of the equipment (e.g. nameplate capacity of EV charger).

- **Service capability:** For each measure, the measure's ability to contribute to each of the four key grid services[4] based on technical capability, operational constraints, and practicality. If relevant, for each grid service, the portion of a measure's nameplate capacity that can be used for a service is defined. For example, for BTM solar, only the portion of the nameplate capacity that expected to generate at times coincident with the system peak would be credited with capacity benefits.

- **Modified load profile:** For each grid service a measure can contribute to, measure-specific parameters and constraints are used to develop a modified profile associated with the provision of the service. The profiles can be set based on top-down constraints (e.g. % of load that can be controlled), or bottom-up assumptions (e.g. maximum number of events called per year, event duration) considering technical, operational and/or convenience constraints.

B.2.2 BTM and FTM Measures

For BTM and FTM generation and storage measures, the following approach is used to characterize measures:

- **Measure size (kW)**: The nameplate capacity of the resource. Measures are sized considering historical trends, assumed sizing practice or other relevant limitations (e.g. roof size, annual consumption, customer peak demand).
- **Generation profile:** The typical hourly energy production over the year for a generating resource (not relevant for storage measures).
- **Service capability:** For each measure, the measure's ability to contribute to each of the four key grid services based on technical capability, operational constraints, and practicality.

FTM SOLAR SIZING

FTM solar farms were assumed to be sized at 10 MW, ensuring that they can still connect to the distribution network (therefore adhering to the study's DER definition), while still achieving economies of scale. It was also assumed that FTM solar farms would orient their systems to optimize their revenues from both energy and capacity.

B.3 Technical Potential Calculation

This section focuses on the calculation methodology and approach used to estimate market-wide technical potential across all measures included in the study.

[4] The four key grid services are (1) energy (inject, arbitrage, and/or surplus baseload generation), (2) capacity, (3) operating reserve, and (4) regulation capacity

B.3.1 Load Analysis

The study team used load data provided by IESO to develop load profiles for nine representative days. The representative days included three types of typical days (peak day, weekday, weekend) within each season (summer, winter, shoulder), as defined by the table below. Additionally, the data provided by IESO was used to determine the contribution of different sectors and end-uses to peak loads, providing the sector-level load curves presented in Volume I of the report.

Table B-3: Definition of Days and Seasons Included in Study

Season			Day		
Summer	**Winter**	**Shoulder**	**Peak Day**	**Weekday**	**Weekend**
June 1st – September 14th (inclusive)	November 15th – February 29th (inclusive)	March 1st – May 31st (inclusive) September 15 – November 14 (inclusive)	Average shape of the top 10 days, scaled to 100% of peak demand	Average of non-peak and non-holiday weekdays	Average of non-peak and non-holiday weekends

B.3.2 Measure-Level Potential

To calculate the total technical potential for each measure, four key metrics are computed:

- **Nameplate capacity**: the product of the measure size (kW) and the market size for each measure. For DR resources, the nameplate capacity is adjusted to account for the assumed portion that can feasibly be used to provide various grid services.
- **Peak capacity reduction**: the nameplate capacity multiplied by a peak coincidence factor, reflecting the coincidence between the measure's load profile and the defined representative peak day (calculated for both summer and winter peak).
- **Energy generated:** the total annual energy production based on the assumed measure size and assumed capacity factor or hourly generation profile.

The metrics are computed for each scenario, considering their associated impacts on the market size.

B.3.3 Competition

The measure-level potential provides insight into the size of the opportunity for individual measures or opportunity areas in isolation. In reality, some measures share the same market opportunity and are mutually exclusive.

In cases where multiple measures could fill the same DER niche (e.g. smart chargers and/or EV telematics) the project team either split the markets to define the expected portion each measure would apply to, or in cases where there was no technical basis to predict the appropriate market split between DER technologies, a competition function was used and the measure with the larger overall capacity reduction potential was selected while other competing measures were excluded. This approach avoids double-counting potential capacity reductions, while still capturing the total size of the available opportunity. The measures explored in this study that are subject to competition are summarized in the table below.

Table B-4: Measure Competition

Competition Group	Competing Measures
EV Charging	For Passenger EV, LDV, MDV, HDV and Buses: EV Smart Charging EV Vehicle-to-Building/Grid (V2B/G)
Residential HVAC	AC Thermostat Thermal Storage
Residential Heat Pump	HP Smart Thermostat Thermal Storage + HP
Small C&I HVAC	Small Commercial Smart Thermostat Commercial HVAC Thermal Storage
Large C&I HVAC	Large Commercial HVAC Control Commercial HVAC Thermal Storage
Refrigeration	Refrigeration Controls Thermal Storage for Refrigeration Applications

This approach is only applied at the technical and economic potential levels. At the achievable level, the adopted market for each measure is defined exclusively to avoid competition between measures. Note that competition between measures (i.e. two measures going after the same market) is distinct from interactive effects between measures (i.e. one measure impacting the potential for another measure). Interactive effects are not considered in technical potential but are explored further when assessing the economic and achievable potential.

To provide insight into the size of the opportunity for individual measures in isolation, the results in the appendix highlight the technical potential for each measure with and without competition.

C. Economic Potential Methodology

Economic potential quantifies the sum of cost-effective contributions from DERs towards system needs over the study period. It captures the portion of the DER technical potential that is cost-effective under a Total Resource Cost (TRC) test. This represents the maximum pool of DERs that can offer net benefits to Ontario's electricity system (i.e. the value of the benefits delivered exceeds the costs of the DER), but does not incorporate considerations affecting real-world market adoption, such as customer preferences or adoption rates.

The following sub-sections describe the study approach to calculating the economic potential for DERs in Ontario.

C.1 Measure Characterization (Economic)

In reference to economic potential, measure characterization refers to the process used to define key measure-specific economic inputs used in the study, including:

- **Measure Upfront Costs**: The incremental cost of equipment (over assumed baseline technology), control devices and telemetry required for each measure where applicable over the study period.[5]
- **Operations and Maintenance (O&M) Costs:** The costs associated with operating and maintaining the DER.
- **Effective Useful Life (EUL):** The assumed lifetime of the equipment and/or controls – expressed in number of years - based on industry standards.

The approach used to characterize measure costs varied by the type of DER; primarily based on the extent to which the measure was adopted for market participation. The table below highlights the approach used to characterize measure upfront and O&M costs. Each measure in the study was assigned to one of the three types and inputs were developed accordingly. Details on the approach and assumptions used for each measure are documented in Appendix F – Measure Screening and Approach.

[5] Where appropriate, the costs assumed in the study include typical interconnection costs associated with deployments of BTM and FTM resources, however some projects in specific geographies or contexts may entail higher requirements that could be cost prohibitive and reduce the cost-effectiveness of these deployments.

Table C-1: Measure Characterization Economic Considerations

DER Type	Measure Uptake Driver	Examples	Assumed Measure Upfront Cost	Assumed Measure O&M Cost
A	Not primarily driven by financial benefits of market/program participation (i.e. DER functionality is a by-product)	Smart thermostats, smart appliances, or back-up generators are adopted by customers predominantly for other benefits (e.g. energy savings, comfort, resiliency)	Cost of controls (if applicable) (e.g. $0 for Wi-Fi-enabled smart thermostats)	Little to no O&M costs (e.g. no assumed incremental O&M for a smart water heater over a conventional water heater) Limited exceptions (e.g. cost of natural gas used by back-up generation and dual-fuel space heating measures)
B	Somewhat driven by financial benefits of market/program participation (i.e. DER functionality is a co-benefit)	Choice to install a smart EV charger or a smart water heater is partly influenced by the incremental benefits	Incremental cost of the measure over the assumed baseline technology (e.g. incremental cost of smart charger over ‘dumb’ charger)	Little to no O&M costs (e.g. no assumed incremental O&M for a smart water heater over a conventional water heater) Limited exceptions (e.g. cost of natural gas used by back-up generation and dual-fuel space heating measures)
C	Predominantly driven by benefits of market / program participation (i.e. DER functionality is the key benefit)	Decision to adopt BTM solar or BTM storage is primarily based on financial returns a customer expects from net-metering, market revenue, or DR programs	Full cost of the measure (e.g. cost of new solar installation)	Full O&M costs of the measure (e.g. cost of storage maintenance and operation)

COST PROJECTIONS

Where applicable, the study captures the expected cost declines for DERs over the study period. Most measures are expected to have low-to-no cost declines; therefore, their costs were constant over the study period (e.g. lighting controls). Other measures are expected to have modest cost declines, and costs were assumed to decline at a set fixed rate. A number of measures are expected to experience significant cost declines (e.g. storage), and cost projections were developed based on industry projections; the cost declines for such measures were used as one of the levers of the modeled scenarios. Cost projections are provided in Appendix F – Measure Screening and Approach.

C.2 Benefit-Cost Framework

The study applies an enhanced Total Resource Cost (TRC) test to assess the cost-effectiveness of DERs, from an electricity system perspective. This is consistent with the framework used by the IESO in its Energy Efficiency Achievable Potential Study (APS), but further accounts for the dynamic services DERs are capable of satisfying, along with a more sophisticated accounting of carbon cost benefits.[6] The benefits DERs contribute to the system are defined as the corresponding grid services avoided and quantified using market proxies where relevant, as well as key costs, defined as the cost associated with securing the DER capacity for the identified service provision. The following sections outline the approach used to quantify each benefit / cost stream.

Benefits

1. Avoided energy costs (carbon costs embedded)
2. Avoided surplus baseload generation (SBG)
3. Avoided generation capacity costs
4. Avoided operating reserves (OR)
5. Avoided regulation capacity (RC)
6. Avoided / deferred transmission capacity costs

Costs

9. Measure upfront costs
10. O&M costs
11. Program, aggregation and/or transaction costs

Total Resource Cost (TRC) Test

ADDITIONAL BENEFITS NOT CONSIDERED

Beyond the benefit streams captured in the study, DERs can contribute to additional benefits to the system and host customers / communities including resilience and added reliability. Such benefits are typically difficult to quantify and therefore have been excluded from the benefit-cost framework, however these may improve the cost-effectiveness of some DERs if considered.

C.2.1 Benefits

This section outlines the approach used to quantify each of the benefits considered in the benefit-cost framework. Additionally, Table C-2 in section C.3.3 summarises the developed avoided cost values for each of the benefit streams. Appendix E highlights the assumptions for key factors that impact the development of the avoided costs for each scenario.

Avoided Energy Costs

The study uses real-time energy costs as a proxy for the avoided energy costs DERs can contribute to. The project team utilized a proprietary hourly dispatch model that simulates the energy offer behaviors of market participants, as well as demand and weather variables, that drive pricing in Ontario's wholesale market, to develop hourly energy price forecasts over the study period. The model and the developed avoided costs

[6] The framework embeds the regulated price of carbon into the avoided energy benefits stream. Of note, this study does not apply a social cost of carbon to the analysis, which distinguishes the Total Resource Cost test approach used in this study from that of a Societal Cost Test approach.

reflect the various market dynamics of Ontario's hybrid market, including the range of incentives underpinning participants' energy offers in the wholesale market (e.g. out-of-market payments via the Global Adjustment). A seasonal and weather-dependent component are incorporated in energy offers by various fuel types to assess the impact on the supply stack at different times of the year. The model also accounts for both planned and unplanned (i.e., forced) outages for all fuel types.

System demand was based on the IESO's Annual Planning Outlook (APO) 2021 net demand outlook with adjustments under the BAU+ and Accelerated scenarios to reflect the increased electrification modeled under those scenarios. Table E-9 in Appendix E provides a summary of the key supply mix assumptions used in the model. Additionally, carbon prices were varied by scenario as described in Appendix E. Under BAU and BAU+, carbon pricing escalates to $170/tonne CO2 by 2030, aligning with the Government of Canada's publication in the *Pan-Canadian Approach to Pricing Carbon Pollution*.[7] Under BAU, Ontario's Environmental Performance Standard (EPS) for electricity generators is assumed to be maintained at the current threshold of 370 tonnes CO2/ GWh. Most gas-fired generation in Ontario operates below this threshold – therefore no carbon price is passed through to real-time energy costs in the BAU scenario. Under BAU+ and Accelerated, the EPS threshold is assumed to be lowered linearly to 0 tonnes CO2/ GWh by 2030.

Avoided Surplus Baseload Generation (SBG) Costs

Ontario currently has a significant amount of baseload supply – nuclear, baseload hydro and variable output – that may offer energy below marginal costs as a result of physical constraints. During Surplus Baseload Generation (SBG) events, the IESO may be forced to curtail generation to maintain supply/demand balance in the Ontario electricity system. Surplus Baseload Generation (SBG) results in low wholesale prices, curtailment of variable renewable generation, spilling at hydro facilities and a high volume of exports to neighboring markets at low prices, and therefore can result in additional costs for Ontario customers through payments for curtailed energy within IESO contracts. Avoided Surplus Baseload Generation costs are determined based on the assumption of a DER's capability to consume additional energy during Surplus Baseload Generation events and return the energy (or avoid consumption) during non-SBG periods (e.g., battery storage, charging an EV, heating hot water). The estimate for avoided cost savings for Surplus Baseload Generation is derived from the outputs of the avoided real-time energy prices. Specifically, the difference between spilled energy cost and marginal resources during the following hours are used to determine Surplus Baseload Generation avoided cost values.

Avoided Generation Capacity

For determining economic potential, the avoided generation capacity cost was estimated as the net cost-of-new-entry (CONE) for a simple-cycle gas-fired turbine (SCGT) generation facility (with escalations occurring throughout the forecast period).[8] However, for the BAU+ and Accelerated scenarios, an estimated net CONE of renewables + storage was assumed as the avoided capacity generation resource. The values used are presented in later in this report in Table E-8: Assumed Capacity Resource by Scenario.

[7] Reference (accessed May 19, 2022): https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html
[8] Value used by IESO to set Capacity Auction Reference Price and Maximum Auction Clearing Price Revision as found in: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ca/ca-20200123-reference-price.ashx

Avoided Operating Reserves

Operating reserves are used by the IESO to maintain system stability during outage events (e.g., forced outage of generation or transmission assets). There are three operating reserve products in Ontario: 10-minute spinning (10S), 10-minute non-spinning (10NS), and 30-minute reserve (30R). The avoided costs for operating reserve products were computed in tandem with the real-time energy market avoided cost forecast. The developed operating reserve prices were based on both the availability of additional energy output and the opportunity cost to market participants associated with providing operating reserve or energy. The opportunity cost was estimated as the lost energy market profits (i.e., real-time energy costs minus the marginal cost offer) that a market participant does not earn when providing operating reserve. For example, if the wholesale market has a surplus of energy availability (e.g. hydro generators are operating at a low capacity), OR prices will be low due to a limited opportunity cost. Similarly, if there is a significant amount of spare gas-fired generation capacity, operating reserve prices will remain low for the same reason. Operating reserve prices are assumed to move higher when system-wide conditions are tighter – meaning there is limited spare energy and the opportunity cost of providing operating reserve compared to earning energy market revenue is high. High energy prices can also incent more generators to come online and will typically lower operating reserve prices when spare energy is available for dispatch. Thus, as DERs increase the available OR on the system, they reduce the chances that tight supply conditions will occur, thereby helping to avoid increased OR prices.

Avoided Regulation Capacity

Variations in electricity demand and supply - between dispatch intervals (i.e., 5-minute) - are addressed by regulation service resources (i.e., frequency response) that adjust their output to maintain frequency and stability. A significant majority of regulation capacity provided in Ontario is from heritage hydroelectric generation assets owned and operated by Ontario Power Generation (OPG). While hydroelectric facilities are excellent regulation capacity providers, battery-based regulation is emerging in many jurisdictions due to its fast response and short development cycles. In this study, the project team determined that the avoided regulation capacity shall be based on estimates of battery-based energy storage levelized cost of capacity. Values are adjusted under BAU+ and Accelerated to reflect more aggressive technology cost declines.

Avoided / Deferred Transmission Capacity Costs

To determine the avoided cost of transmission, regional planning documents were reviewed to identify sub-regions or local areas within Ontario's system where power system needs are primarily expected to be determined by thermal capacity overload (e.g., demand expected to exceed Limited Time Rating (LTR) of a transmission station). End-of-life and system stability needs were not accounted for within this analysis due to the case-by-case nature of needs and limited information available in public regional planning documents.

A model of demand growth expectations and estimates of existing system capacity for each identified sub-region was constructed to determine specific investment need dates for each sub-region. Given that new transmission investments typically come in the form of fixed capacity blocks (e.g., new transformer station with a capacity of 150 MW), depending on demand growth expectations, the utilization of new transmission investments could be low and provide an opportunity for DERs to defer investments until higher utilization can be ensured. The savings potential for deferment of new traditional transmission investments is based on the avoidance of annual amortization payments calculated using typical utility costs of capital and capital costs.

Avoided / Deferred Distribution Capacity Costs

Local Distribution Companies' (LDC) capital expenditures are primarily used to maintain, upgrade, and expand distribution networks, with only a subset of annual spending used to expand the distribution system for thermal capacity needs and/or outage management requirements. The OEB defines system service as "modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements."

System service was used as a fair representation of system expansion spending to meet future customer needs and was therefore used as a proxy for avoided distribution costs. A forecast of future distribution capital expenditures under system service was developed based on historic trends in capital expenditures and load growth for the province. The analysis of deferment potential for DERs assumed, based on vetting with multiple LDCs, that between 10% and 20% of system service spending could be deferred annually by the deployment of DERs. The used percentages are based on identified historic LDC spending patterns.

T&D Line Losses

Line losses were applied to real-time energy costs in the wholesale electricity market for distribution-connected customers. Each LDC has slightly different line losses within its distribution network based on customer types, service area, operating voltage, and other factors. A line losses percentage was calculated for all distribution networks across Ontario. The line loss factor was then applied to the forecasted real-time energy avoided costs to estimate the benefits associated with avoiding T&D line losses.

C.2.2 Costs

Measure Costs

As described in section C.1 Measure Characterization (Economic)

Measure O&M Costs

As described in section C.1 Measure Characterization (Economic).

Program, Aggregation, and/or Transaction Costs

Typical administration, marketing, resource acquisition and other costs needed to enable DER participation in markets are captured in the benefit-cost framework and cost-effectiveness analysis. The costs used are based on Dunsky's DR Program Archetype Library - which builds on research and insights from utility-run DR programs. While these may differ from program costs incurred by aggregators in Ontario, they reflect a defensible proxy for the cost of acquiring the resources.

The following program cost assumptions were employed in the study:

- **Residential and small commercial DR**: $50/participant/year
- **Large commercial and industrial DR:** $15/kW
- **Behavioral DR:** $20/participant/year

No programs costs associated with BTM generation or FTM resources were added.

C.3 Economic Potential Assessment

C.3.1 System Needs

In assessing the economic potential for DERs, the analysis takes into consideration the projected system needs for the various services considered in the study. The economic potential assessment constrains each benefit stream to the projected system needs that DERs can feasibly contribute to, after which additional DERs added to the system would deliver little or no further benefit for that specific value stream. While the focus is on defining annual system needs for each service, where applicable, the service needs for some services are defined by a season/time window. Most notably, generation capacity system needs are defined as per the forecasted peak window.[9]

This section highlights the approach used to arrive at the service need for each service over the study period by scenario. The resulting values are highlighted below in Table C-3.

- **Energy:** The maximum service DERs can utilize for the avoided real-time energy was determined by the hourly capacity of gas-fired generation and imports. The reason for limiting the maximum service is due to Ontario's unique hybrid electricity market structure. Almost all supply resources in the province are contracted or rate-regulated to ensure generator revenue sufficiency. Global Adjustment is the funding mechanism that provides a "top-up" payment for supply resources when market revenues are not sufficient. A majority of the supply resources have revenue sufficiency commitments for the forecast period (i.e., nuclear, hydroelectric and most non-hydro renewables). Any reduction in real-time energy costs for those supply resources will result in higher Global Adjustment for customers and limited avoided cost value. For gas-fired generation, many of the current contracts and future procurements for existing resources (e.g., IESO's Medium Term RFP) are expected to be on a fixed capacity basis; therefore, reduction in real-time energy prices when those resources are operating can result in avoided energy costs. Imports are exposed to market prices. The same maximum service as real-time energy was used for line losses.
- **Avoiding SBG:** All zero or negative pricing hours in the hourly energy price forecasts were identified as times when Surplus Baseload Generation events could occur. For each zero or negative energy price hour, a maximum service for Surplus Baseload Generation was determined based on estimated curtailment of wind generation in that given hour.
- **Capacity:** The maximum service for avoided capacity was determined based on a combination of short-term Annual Acquisition Report (AAR) capacity auction expectations and longer-term resource adequacy needs as identified in the APO 2021. Specifically, short-term capacity needs that will rely on the IESO's Capacity Auctions were used to establish minimum capacity targets for both the winter and summer commitment period for 2023-2024. The APO 2021 reference forecast and the associated capacity deficit was used to reflect long-term capacity needs. The values were adjusted for the BAU+ and Accelerated scenarios to reflect the impact of the forecasted electrification load growth on demand and resource adequacy.
- **Operating Reserves:** The maximum service for operating reserve was determined based on the reliability and operating requirements of the IESO-Administered Markets. For example, the IESO is obligated to have enough 10-minute reserve (i.e., 10S + 10NS) to cover the largest single contingency

[9] Given the province-wide focus of the study, transmission and distribution system peaks are assumed to be aligned with system-wide peak observed by the IESO. In reality, some sub-regions of the transmission systems and/or different LDCs will have peaks non-coincident with the system-wide peak.

that can occur (e.g., a forced outage of a nuclear unit or forced outage of a transmission line). The 30-minute reserve is the greater of (a) half the second largest contingency or (b) the largest commissioning generating unit.

- **Regulation Capacity:** Currently, the IESO schedules nearly 100 MW of regulation capacity an hour to meet system needs. Moving forward, Ontario will require increased amounts of regulation capacity as demand patterns change due to innovative technologies (e.g. energy storage and flexible demand) and variable renewable energy resources (e.g. wind, solar) becoming increasingly prevalent. Based on estimates of current and future regulation capacity need, we assessed that roughly 150 MW will be needed over the study period.
- **Transmission Capacity:** The maximum service for transmission capacity needs is based on the identified future capacity deficit across the province for all regions. Refer to "Avoided / Deferred Transmission Capacity Costs" in Section C.3.2 for the approach used to develop avoided transmission capacity costs.
- **Distribution Capacity:** The maximum service was based on provincial load growth expectations and future distribution system deferment value. Refer to "Avoided / Deferred Distribution Capacity Costs" in Section C.3.2 for the approach used to develop avoided distribution capacity costs.

C.3.2 Measure-level cost-effectiveness screening

The measure-level economic potential provides insight into a measure's cost-effectiveness and potential when it's considered in isolation.

- **Measure Dispatch:** The DER model automatically adjusts the dispatch profile of each measure to optimize its benefit to the system. For example, the model selects the optimal time to engage a water-heater DR measure based on its baseline load profile, the system service being delivered, and the duration of the equipment's ability to provide that service. For each DER measure-segment combination, the model's optimizer is used to identify the dispatch strategy that would maximize benefits from the resource, while respecting a set of constraints outlined in the measure characterizations (e.g. service capability, number of calls, etc.) as well as any constraints defined by the system/service need (e.g. peak window, magnitude of need). This allows not only the creation of the optimal dispatch profile for the resource, but also for every possible combination of services (energy, OR, etc.) to find the most economic strategy. This is performed independently for the nine typical days defined in the study for each year in the study. In dispatching the measures, it was assumed that DERs can contribute to all services that they were identified as capable of - regardless of existing market participation or compensation rules. In dispatching the measures, services with the highest economic value are prioritized (e.g. capacity, energy), and other service contributions are added without overlapping with primary services and while respecting the appropriate measure and system constraints (e.g. number of service calls, cool down window, etc.).
- **Benefits calculation:** The measure's assumed dispatches over the nine standard days are "stitched" together to create an hourly load shape for every year in the study period. The load shape is then mapped to the developed hourly avoided costs to estimate the annual benefits the measure can contribute to. To capture the diminishing impacts some DERs may have as incremental additions are added to the market, our model considers the impact of sub-additions of the measure to assess the marginal value of additions

and determine what portion of the technical potential can be deployed cost-effectively until an additional unit is no longer cost-effective.

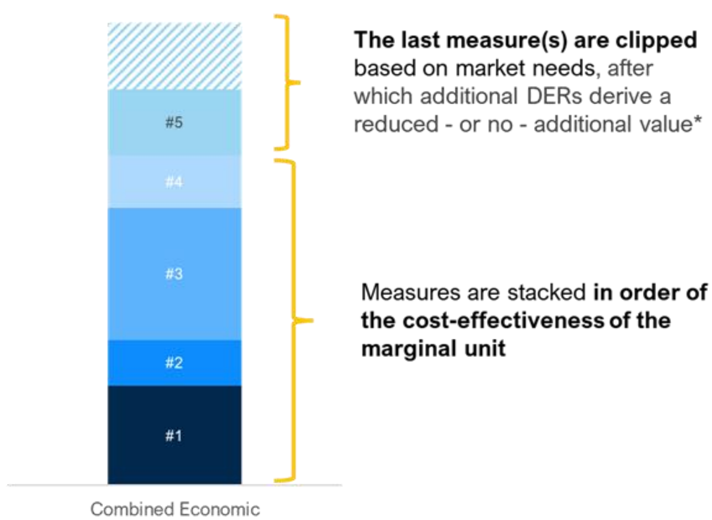
For example, in the 2032 measure-level economic results (no interaction / competition with other measures) for the BAU scenario, the first FTM solar unit of 10MW will get full capacity benefits and energy benefits, generating enough benefits to yield a TRC slightly above 1.9. However, the 71st unit (710 MW total) does not generate as many benefits, since some of the units previously assessed are already capturing most of the available benefits (e.g. there's no more need for energy around noon, when solar is peaking). Therefore, that 71st unit only has a TRC of 1 and any further unit addition will yield a TRC below 1 and will be deemed not cost-effective.

- **Measure-Level TRC:** To assess the cost-effectiveness, the net present value of the lifetime benefits and costs associated with a measure are computed to arrive at a TRC ratio for each measure.[10] Measures with a TRC greater than 1.0 are considered cost-effective.

C.3.3 Market-wide economic potential

The market-wide economic potential reflects the combined economic potential of all cost-effective measures when they are considered and applied in tandem towards meeting the identified system needs.

Specifically, starting with the most valuable grid service (i.e. capacity), measures that passed the measure-level cost-effectiveness screening are stacked in order of cost-effectiveness up to the maximum system need *or* until no incremental cost-effective DER potential remained. The most cost-effective measures (at the segment-level) are called upon until all the cost-effective potential of the measure has been exhausted, and the next measure in the stack is called upon for the service provision. As measures are stacked, measure cost-effectiveness was recalculated in cases where there was expected to be a significant change in cost-effectiveness due to interactive effects and/or changes in service provision that may impact the measure's competitiveness (e.g., change in peak coincidence factor).



If the economic potential for the last dispatched measure exceeds the remaining system needs, the economic potential is clipped based on market needs, after which additional DERs derive no additional value. However, measures are allowed to contribute to the service beyond market needs as a by-product of contributing to another service (e.g., energy, T&D), but receive reduced - or no - additional value for the already fulfilled service. The process is repeated for the remaining grid services until all economic potential is exhausted or system needs are met – whichever is reached first.

[10] A 6% discount rate is applied.

Table C-2 provides the avoided costs for each service by scenario. It is notable in Table C-4: Supply Mix Assumptions by Scenario (MW) that the Accelerated scenario has fewer resources being deployed than BAU or BAU+, as it is assumed in this scenario that there will be limited new resource additions beyond current plans and commitments. Due to this, the increased electricity demand in the later years resulting from high levels of electrification cause the energy prices to spike as supply becomes short. See **E.5 Supply Resource Mix** for more information.

Table C-2: Summary of Developed Avoided Costs by Scenario (Average Annual Values – $2021)

	Avoided Energy Costs	Avoided Surplus Baseload Generation	Avoided Generation Capacity (Summer)	Avoided Generation Capacity (Winter)	Avoided operating reserves (OR) [10-minute spinning]	Avoided operating reserves (OR) [10-minute non-spinning]	Avoided operating reserves (OR) [30-minute]	Avoided regulation capacity (RC)[11]	Avoided / deferred transmission capacity costs	Avoided / deferred distribution capacity costs
	$/MWh	$/MWh	$/MW-day	$/MW-day	$/MWh	$/MWh	$/MWh	$/MW-day	$/MW-day	$/MW-day
BAU										
2023	$33.33	$101.68	$593	$593	$8.47	$6.92	$4.48	$483.60	$112.26	$4.28
2024	$27.70	$104.52	$608	$608	$6.04	$4.93	$3.21	$457.99	$112.26	$4.28
2025	$30.28	$104.81	$617	$617	$6.87	$5.58	$3.64	$433.74	$112.26	$4.28
2026	$32.67	$104.80	$629	$629	$8.07	$6.69	$4.28	$419.68	$112.26	$4.28
2027	$33.85	$104.48	$642	$642	$8.60	$6.98	$4.55	$406.07	$112.26	$4.28
2028	$34.81	$103.57	$655	$655	$8.69	$7.07	$4.56	$392.90	$112.26	$4.28
2029	$37.16	$102.71	$668	$668	$9.54	$7.91	$5.08	$380.16	$112.26	$4.28
2030	$39.60	$102.16	$681	$681	$11.07	$8.98	$5.81	$367.84	$112.26	$4.28
2031	$39.08	$102.11	$695	$695	$10.00	$8.25	$5.33	$362.83	$112.26	$4.28
2032[12]	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2033	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2034	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2035	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2036	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2037	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2038	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2039	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28
2040	$38.25	$102.10	$709	$709	$9.13	$7.49	$4.83	$357.90	$112.26	$4.28

[11] Based on a 2-hour storage resource.
[12] Costs were kept constant after 2032 in the BAU scenario.

	Avoided Energy Costs	Avoided Surplus Baseload Generation	Avoided Generation Capacity (Summer)	Avoided Generation Capacity (Winter)	Avoided operating reserves (OR) [10-minute spinning]	Avoided operating reserves (OR) [10-minute non-spinning]	Avoided operating reserves (OR) [30-minute]	Avoided regulation capacity (RC)[11]	Avoided / deferred transmission capacity costs	Avoided / deferred distribution capacity costs
	$/MWh	$/MWh	$/MW-day	$/MW-day	$/MWh	$/MWh	$/MWh	$/MW-day	$/MW-day	$/MW-day
BAU+										
2023	$40.19	$101.68	$675.13	$675.13	$10.01	$8.21	$4.48	$483.60	$112.26	$4.28
2024	$32.80	$104.52	$688.63	$688.63	$7.19	$5.89	$3.21	$457.99	$112.26	$4.28
2025	$44.51	$104.81	$702.41	$702.41	$6.70	$5.52	$3.64	$433.74	$112.26	$4.28
2026	$57.72	$104.80	$716.46	$716.46	$7.42	$6.26	$4.28	$419.68	$112.26	$4.28
2027	$66.52	$104.48	$730.78	$730.78	$8.06	$6.69	$4.55	$406.07	$112.26	$4.28
2028	$71.63	$103.57	$745.40	$745.40	$12.02	$9.90	$4.56	$392.90	$112.26	$4.28
2029	$82.84	$102.71	$760.31	$760.31	$12.65	$10.56	$5.08	$380.16	$112.26	$4.28
2030	$90.48	$102.16	$775.51	$775.51	$14.61	$12.01	$5.81	$367.84	$112.26	$4.28
2031	$93.32	$102.11	$791.02	$791.02	$15.34	$12.84	$5.33	$362.83	$112.26	$4.28
2032	$92.94	$102.10	$806.85	$806.85	$15.29	$12.74	$4.83	$357.90	$112.26	$4.28
2033	$87.95	$102.11	$822.98	$822.98	$13.69	$11.47	$3.95	$357.90	$112.26	$4.28
2034	$87.60	$102.11	$839.44	$839.44	$13.20	$10.98	$3.66	$357.90	$112.26	$4.28
2035	$81.03	$102.12	$856.23	$856.23	$11.47	$9.58	$2.98	$357.90	$112.26	$4.28
2036	$80.22	$102.12	$873.36	$873.36	$12.14	$10.20	$3.33	$357.90	$112.26	$4.28
2037	$82.07	$102.13	$890.82	$890.82	$12.11	$10.09	$3.40	$357.90	$112.26	$4.28
2038	$82.79	$102.13	$908.64	$908.64	$12.70	$10.68	$3.66	$357.90	$112.26	$4.28
2039	$91.76	$102.14	$926.81	$926.81	$19.67	$16.54	$5.26	$357.90	$112.26	$4.28
2040	$87.87	$102.14	$945.35	$945.35	$16.28	$13.83	$3.98	$357.90	$112.26	$4.28

	Avoided Energy Costs	Avoided Surplus Baseload Generation	Avoided Generation Capacity (Summer)	Avoided Generation Capacity (Winter)	Avoided operating reserves (OR) [10-minute spinning]	Avoided operating reserves (OR) [10-minute non-spinning]	Avoided operating reserves (OR) [30-minute]	Avoided regulation capacity (RC)[11]	Avoided / deferred transmission capacity costs	Avoided / deferred distribution capacity costs
	$/MWh	$/MWh	$/MW-day	$/MW-day	$/MWh	$/MWh	$/MWh	$/MW-day	$/MW-day	$/MW-day
Accelerated										
2023	$37.21	$101.68	$675.13	$675.13	$10.01	$8.21	$4.48	$483.60	$116.80	$4.46
2024	$31.95	$104.52	$688.63	$688.63	$7.19	$5.89	$3.21	$457.99	$119.14	$4.55
2025	$49.61	$104.81	$702.41	$702.41	$6.70	$5.52	$3.64	$433.74	$121.52	$4.64
2026	$63.29	$104.80	$716.46	$716.46	$7.42	$6.26	$4.28	$419.68	$123.95	$4.73
2027	$85.18	$104.48	$730.78	$730.78	$8.06	$6.69	$4.55	$406.07	$126.43	$4.82
2028	$103.50	$103.57	$745.40	$745.40	$12.02	$9.90	$4.56	$392.90	$128.97	$4.92
2029	$115.78	$102.71	$760.31	$760.31	$12.65	$10.56	$5.08	$380.16	$131.55	$5.02
2030	$180.82	$102.16	$775.51	$775.51	$14.61	$12.01	$5.81	$367.84	$134.18	$5.12
2031	$241.13	$102.11	$791.02	$791.02	$15.34	$12.84	$5.33	$362.83	$136.86	$5.22
2032	$374.36	$102.11	$806.85	$806.85	$15.29	$12.74	$4.83	$357.90	$139.58	$5.33
2033	$286.45	$102.11	$822.98	$822.98	$13.69	$11.47	$3.95	$357.90	$142.38	$5.43
2034	$298.84	$102.11	$839.44	$839.44	$13.20	$10.98	$3.66	$357.90	$145.22	$5.54
2035	$296.28	$102.12	$856.23	$856.23	$11.47	$9.58	$2.98	$357.90	$148.13	$5.65
2036	$378.41	$102.12	$873.36	$873.36	$12.14	$10.20	$3.33	$357.90	$151.09	$5.76
2037	$373.10	$102.13	$890.82	$890.82	$12.11	$10.09	$3.40	$357.90	$154.11	$5.88
2038	$457.53	$102.13	$908.64	$908.64	$12.70	$10.68	$3.66	$357.90	$157.19	$6.00
2039	$556.07	$102.14	$926.81	$926.81	$19.67	$16.54	$5.26	$357.90	$160.34	$6.12
2040	$558.01	$102.14	$945.35	$945.35	$16.28	$13.83	$3.98	$357.90	$163.55	$6.24

Table C-3: Summary of System Needs by Scenario

	Energy	Surplus Baseload Generation	Capacity (Summer)	Capacity (Winter)	Operating reserves (OR) [10-minute spinning]	Operating reserves (OR) [10-minute non-spinning]	Operating reserves (OR) [30-minute]	Regulation capacity (RC)	Avoided / deferred transmission capacity	Avoided / deferred distribution capacity
	TWh	MWh	MW	MW	MW	MW	MW	MW	MW	MW
BAU										
2023	28.73	108.65	1,200	1,550	206	619	413	150	141	108
2024	21.43	15.45	1,515	1,725	206	619	413	150	747	131
2025	26.13	105.82	1,818	1,800	206	619	413	150	934	153
2026	36.37	12.88	2,653	2,518	206	619	413	150	1,005	184
2027	36.94	0.00	4,284	2,084	206	619	413	150	1,179	198
2028	33.12	1.88	3,688	1,692	206	619	413	150	1,431	237
2029	35.49	2.75	4,823	3,084	206	619	413	150	1,736	255
2030	35.59	0.00	3,965	2,596	206	619	413	150	2,032	266
2031	34.90	4.02	5,589	3,661	206	619	413	150	2,383	274
2032	31.90	0.00	4,333	3,051	206	619	413	150	2,434	289
BAU+										
2023	30.59	6.44	1,200	1,550	206	619	413	150	142	133
2024	23.32	56.44	2,271	1,725	206	619	413	150	795	162
2025	24.85	4.03	1,954	1,796	206	619	413	150	1,013	198
2026	33.33	0.00	3,140	3,231	206	619	413	150	1,122	238
2027	34.74	0.00	5,335	3,075	206	619	413	150	1,335	238
2028	31.78	0.00	4,718	2,992	206	619	413	150	1,628	301
2029	36.10	0.00	5,706	5,000	206	619	413	150	1,945	349
2030	37.54	0.00	5,351	5,088	206	619	413	150	2,327	396
2031	39.29	0.00	6,465	8,128	206	619	413	150	2,734	432
2032	39.10	0.00	5,457	9,064	206	619	413	150	2,846	454

	Energy	Surplus Baseload Generation	Capacity (Summer)	Capacity (Winter)	Operating reserves (OR) [10-minute spinning]	Operating reserves (OR) [10-minute non-spinning]	Operating reserves (OR) [30-minute]	Regulation capacity (RC)	Avoided / deferred transmission capacity	Avoided / deferred distribution capacity
	TWh	MWh	MW	MW	MW	MW	MW	MW	MW	MW
Accelerated										
2023	35.1	0.7	1,200	500	206	619	413	-	206	142
2024	28.4	6.4	1,400	500	206	619	413	-	1,097	179
2025	34.7	0.5	2,972	500	206	619	413	150	1,424	223
2026	45.4	0	5,755	1,621	206	619	413	150	1,599	267
2027	55.2	0	5,587	1,707	206	619	413	150	1,918	303
2028	56.4	0	6,438	4,590	206	619	413	150	2,345	366
2029	67.6	0	6,740	5,369	206	619	413	150	2,848	452
2030	75.7	0	8,544	8,134	206	619	413	150	3,360	560
2031	82.4	0	8,643	11,499	206	619	413	200	3,950	788
2032	88.2	0	9,282	14,603	206	619	413	200	4,153	959

Table C-4: Supply Mix Assumptions by Scenario (MW)

	Nuclear	Hydro	Gas	Solar	Wind	Storage	Biomass
BAU							
2023	12,906	8,698	9,492	492	5,195	-	245
2024	12,906	8,698	9,492	492	5,195	250	245
2025	11,876	8,698	9,492	492	5,195	250	245
2026	9,812	8,698	9,492	592	5,195	250	245
2027	9,812	8,698	9,492	692	5,195	250	245
2028	9,812	8,698	9,492	792	5,195	250	245
2029	9,812	8,698	9,492	892	5,195	950	245
2030	10,112	8,698	9,493	992	5,525	950	245
2031	10,112	8,698	9,493	1,242	5,855	1,650	245

	Nuclear	Hydro	Gas	Solar	Wind	Storage	Biomass
2032	10,112	8,698	9,493	1,492	6,185	1,650	245
BAU+							
2023	12,906	8,698	9,492	492	5,195	-	245
2024	12,906	8,698	9,492	492	5,195	-	245
2025	11,876	8,698	9,492	492	5,195	250	245
2026	9,812	8,698	9,492	592	5,195	250	245
2027	9,812	8,698	9,492	692	5,195	250	245
2028	9,812	8,698	9,492	792	5,195	250	245
2029	9,812	8,698	9,492	892	5,195	1,250	245
2030	10,112	8,698	9,493	1,192	5,635	1,650	245
2031	10,112	8,698	9,493	1,492	6,075	1,650	245
2032	10,112	8,698	9,493	1,792	6,515	1,900	245
Accelerated							
2023	12,906	8,698	9,492	592	5,195	-	245
2024	12,906	8,698	9,492	642	5,195	250	245
2025	11,876	8,698	9,492	692	5,195	250	245
2026	10,312	8,698	9,492	742	5,195	250	245
2027	9,812	8,698	9,492	792	5,195	250	245
2028	9,812	8,698	9,492	842	5,195	600	245
2029	9,812	8,698	9,492	892	5,195	600	245
2030	10,112	8,698	9,493	942	5,225	600	245
2031	10,112	8,698	9,493	992	5,255	600	245
2032	10,112	8,698	9,493	1,042	5,285	950	245

D. Achievable Potential Methodology

The achievable potential represents the expected contribution of DERs to Ontario's system needs over the next decade, considering consumer preferences, market dynamics, and evolving electricity demand assumed under each scenario. The following sub-sections describe the study approach to calculating the achievable potential for DERs in Ontario.

DER Adoption → Market Participation → System Impacts

D.1 DER Adoption

DER adoption refers to the uptake of a given technology by customers as determined by the economic attractiveness of the DER measure to a customer, and considering market barriers. The approach used to assess the market adoption of the DERs considered in this study varied based on the type of DERs, and specifically whether it was assumed to be predominantly adopted for market participation or not. Each measure in the study was assigned to one of the three types. Details on the approach and assumptions used for each measure are highlighted in Appendix F – Measure Screening and Approach.

Table D-1: DER Adoption Assumptions and Approach

DER Type	Assumption	Examples	Market Adoption Approach
A	**Not primarily driven** by financial benefits of market/program participation (i.e. DER functionality is a by-product)	Smart thermostats, smart appliances, or back-up generators are adopted by customers predominantly for other benefits (e.g. energy savings, comfort, resiliency)	Expected penetration of the technology in the market will be **based on market data and trends** (e.g. number of smart clothes dryers from the Residential End-Use Survey (REUS))
B	**Somewhat driven** by financial benefits of market/program participation (i.e. DER functionality is a co-benefit)	Choice to install a smart EV charger or a smart water heater is partly influenced by the incremental benefits	Expected penetration of the technology in the market will be **based on adjusted market trends** with adjustments to reflect the market growth expected to be observed under different scenarios as relevant
C	**Predominantly driven** by financial benefits of market/program participation (i.e. DER functionality is the key benefit)	Decision to adopt BTM solar or BTM storage is primarily based on financial returns a customer expects from net-metering, market revenue, or DR programs	**Detailed market adoption modeling** for each scenario based on market participation benefits

Details on the approach and assumptions used for Type A and B measures are highlighted in Appendix F – Measure Screening and Approach. The approach used for Type C measures is further detailed in the next section.

D.1.1 Approach for Type C Measures

For Type C measures, the study team used Dunsky's in-house solar and storage adoption models to forecast the uptake of the respective technologies using the following approach:

- **Technical potential:** The estimated theoretical maximum deployment potential for each technology as defined in the technical potential (See Appendix B).
- **Customer characterization:** To determine the benefits customers could unlock from a given technology, our team mapped the study segments into their representative rate classes. Based on the average annual consumption and the maximum load per customer for a given segment, segments were assigned energy rates, distribution rate classes and GA classification. For distribution / delivery rates and TOU, Hydro One's values were used as a proxy.

Table D-2: Customer Characterization for Type C Measures

	Segment	Annual Consumption per Customer (kWh)	Peak Load per Customer (kW)	Energy Rates	Hydro One Rate Code	GA
Residential	Single Family	12,563	3	RPP/TOU	SR	N/A
	Row House	11,885	3	RPP/TOU	R2	N/A
	Low-Rise MURB	6,252	2	RPP/TOU	R1	N/A
	High-Rise MURB	5,812	2	RPP/TOU	UR	N/A
	Other Residential	13,345	5	RPP/TOU	UR	N/A
Commercial	Office	25,148	6	RPP/TOU	UGe	N/A
	Large Office	4,519,667	1,066	HOEP	ST	Class A
	Non-Food Retail	535,342	120	HOEP	UGD	Class B
	Large Non-Food Retail	14,993,696	3,441	HOEP	ST	Class A
	Food Retail	3,824,526	792	HOEP	ST	Class B
	Restaurant	228,191	48	RPP/TOU	UGe	N/A
	Hotel	110,448	22	RPP/TOU	UGe	N/A
	Large Hotel	3,927,919	949	HOEP	ST	Class B
	Hospital	6,778,682	1,715	HOEP	ST	Class A
	Nursing Home	471,534	88	HOEP	UGD	Class B
	School	690,839	161	HOEP	UGD	Class B
	University & College	2,781,427	520	HOEP	ST	Class B
	Warehouse / Wholesale	574,867	117	HOEP	UGD	Class B
	Other Commercial	135,526	38	RPP/TOU	UGe	N/A
Industrial	All segments	N/A	N/A	HOEP	ST	Class A

- **Customer Economics:** The benefits and costs associated with the measures are calculated and used to develop the expected annual cash-flows over the lifetime of the measure. A financial metric is computed (e.g. payback) for each year of the study period to capture the economics of adoption for the DER in a given year. Due to differences in decision-making criteria and economic threshold, simple payback (years) is assumed to be used by residential customers in considering solar adoption, while Internal Rate of Return (IRR) is assumed to be used by more sophisticated commercial and industrial customers. The financial metrics are then passed through willingness-to-adopt curves that highlight the portion of the technical market willing to adopt the technology at different levels of returns. Additionally, the curves capture customers who may pursue the technology at lower cost-effectives for non-financial motivations (e.g. resiliency). Multiple standard curves are integrated in the model and one is chosen based on calibrating the model to the local market. The curves represent findings from empirical research that leverage real-world adoption insights as well as customer surveys across various jurisdictions that highlight customers' willingness-to-adopt different technologies at various price points. Retail rates used in this analysis are presented in the Table D-3.

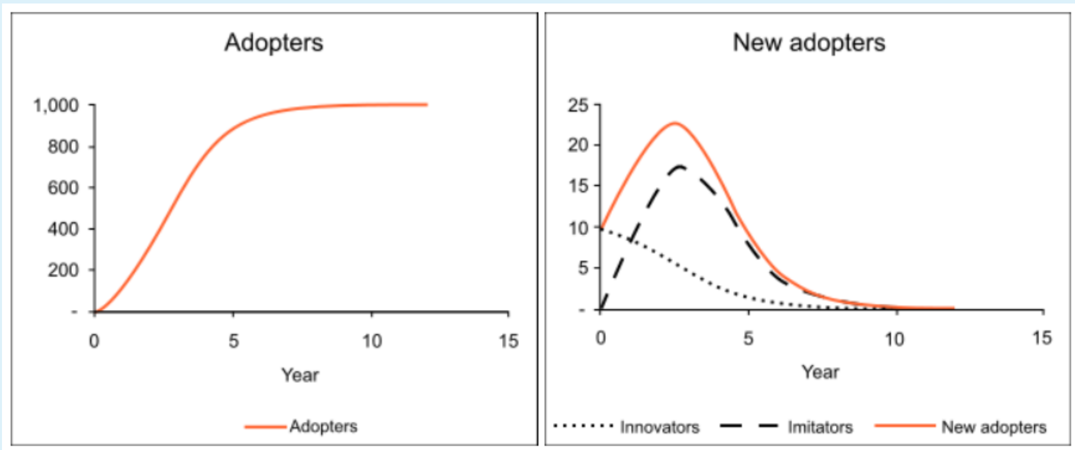
Table D-3: Electricity Retail Rates – Growth Rate

Scenario	Compound Annual Growth Rate	Approach
BAU	1.09%	Based on expected avoided costs of energy (including carbon).
BAU+	1.50%	Based on expected avoided costs of energy (including carbon).
Accelerated	7.50%	Adjusted from the expected avoided costs of energy (including carbon). Assumes that regulated electricity rates would not be allowed a step increase over a few years. Note: avoided costs of energy in this scenario increase at an annualized rate of 30% over the study period.

- **Technology adoption:** To estimate the rate of adoption of each DER over the study period, technology adoption and diffusion theory captured through a Bass diffusion curve is used to estimate the local deployment of over time. The Bass diffusion curve is used to determine the maximum achievable market size given the technology and market maturity in a given year. To capture the local market characteristics and barriers, the model is calibrated to Ontario by benchmarking the model's outputs to historical uptake trends by adjusting the Bass diffusion parameters as well as the choice of economic curves. The calibrated parameters are then used in developing the forward-looking projections.

THE BASS DIFFUSION CURVE

The Bass diffusion curve consists of a differential equation that describes the process of how new products get adopted across a population. The Bass diffusion curve highlights the maximum achievable market size given the technology and market maturity at a given year.



$$Adoption\ Rate\ (t) = \frac{1 - e^{-(p+q)T}}{1 + \left(\frac{q}{p}\right) e^{-(p+q)T}}$$

Where *T* is the time from the initial year the product was introduced, *p* represents the "coefficient of innovation" characterizing early adopters of a technology, and *q* represents the "coefficient of imitation" characterizing late adopters of a technology.

Table D-4: Bass diffusion curve parameters for BTM Solar and Storage

DER	Sector	p	q
BTM Solar and Storage	Residential	0.001	0.170
	Commercial	0.001	0.170
FTM Solar, Hydro, Storage	N/A	0.00111	0.175

Six key measure groups were identified as type C. The table below highlights the approaches used to assess their market adoption.

Table D-5: Approaches used to Assess Measure Market Adoption

DER	Approach Overview	Key Value Streams Considered
BTM Solar	Detailed adoption modeling of standalone solar and solar + storage for each of the study segments was used to estimate the forecasted uptake over the study period. The markets for each were then redistributed to develop separate adoption projections for solar PV and storage. Calibrated to historical BTM solar uptake under microFiT and NEM.	Benefits: Net-Metering (TOU / HOEP) Costs: Equipment and O&M Costs
BTM Storage	Detailed adoption modeling of standalone storage and solar + storage for each of the study segments to was used estimate the forecasted uptake over the study period. Given the limited data availability on BTM storage uptake, BTM solar uptake was used as a proxy for the expected technology diffusion in the market to calibrate the model.	Benefits: Arbitrage (TOU / HOEP) ICI + Demand Charge (as applicable) Applicable market revenues as varied by scenario Costs: Equipment and O&M Costs
FTM Solar	Detailed assessment of the annual cashflows for an average deployment of each technology and the expected returns relative to investor required returns was used to forecast uptake over the study period. Calibrated to historical microFiT uptake.	Benefits: Applicable market revenues as varied by scenario Costs: Equipment, O&M Costs
FTM Storage	Detailed assessment of the annual cashflows for an average deployment of each technology and the expected returns relative to investor required returns was used to forecast uptake over the study period. Calibrated to historical microFiT uptake.	Benefits: Applicable market revenues as varied by scenario Costs: O&M Costs, Demand Charges *Note: For battery-based energy storage, an annual total cost of ownership was used, which incorporates facility amortized installed costs and annual O&M charges. As the storage facility's storage modules degrade, this total cost of ownership accounts for module replacement or potential expansion to meet future system needs.*

DER	Approach Overview	Key Value Streams Considered
FTM Small-scale hydro	Detailed assessment of the annual cashflows for an average deployment of each technology and the expected returns relative to investor required returns was used to forecast uptake over the study period. Calibrated to historical microFiT uptake.	Benefits: Applicable market revenues as varied by scenario Costs: Equipment and O&M Costs
Thermal Storage	The forecasted adoption of BTM storage in terms of penetration (i.e. % of total market) is applied to thermal storage market as a proxy for the forecasted uptake over the study period.	Derived from BTM Storage

The analysis was conducted for applicable segments by year and scenario to forecast DER uptake in the province over the next decade. For each scenario, technology cost declines, market revenues and electricity rates were changed to reflect the assumptions under each scenario.

FORECASTS OF CAPACITY AUCTION PRICES

In addition to the avoided generation capacity costs used for the purpose of the economic potential assessment, the project team developed a forecast of future Capacity Auction prices for both the winter and summer commitment periods as a representation of the market revenues available to DERs under the achievable potential scenarios.

Resource requirement expectations in Capacity Auctions were determined based on publicly available information (e.g., APO and AAR) and Power Advisory expectations for resource development as described in the avoided real-time energy costs. Supply resources participating in the Capacity Auctions are based on four generation participation types:

- **Demand response & behind-the-meter resources:** derived from historic Capacity Auction prices in Ontario and neighbouring markets along with assumptions of future technology costs.
- **Existing resources:** net capacity costs for existing resources coming off contract (e.g., gas-fired generation).
- **New resource development:** capacity costs for new resource development (e.g., renewables, energy storage, low carbon (RNG or Hydrogen) gas-fired generation, load customer energy centres).
- **Non-firm imports:** non-firm imports are set at the capacity auction price cap and the quantity available is based on the existing and committed (in Power Advisory's view) intertie capacity limits.

D.2 DER Participation

DER participation is defined as the portion of customers who have adopted a given technology that are willing to participate in DER programs or in markets to provide grid services. Participation levels are calculated based on participation/performance incentive and/or market revenue available to the customers, program marketing efforts and the barriers associated with participation for each measure.

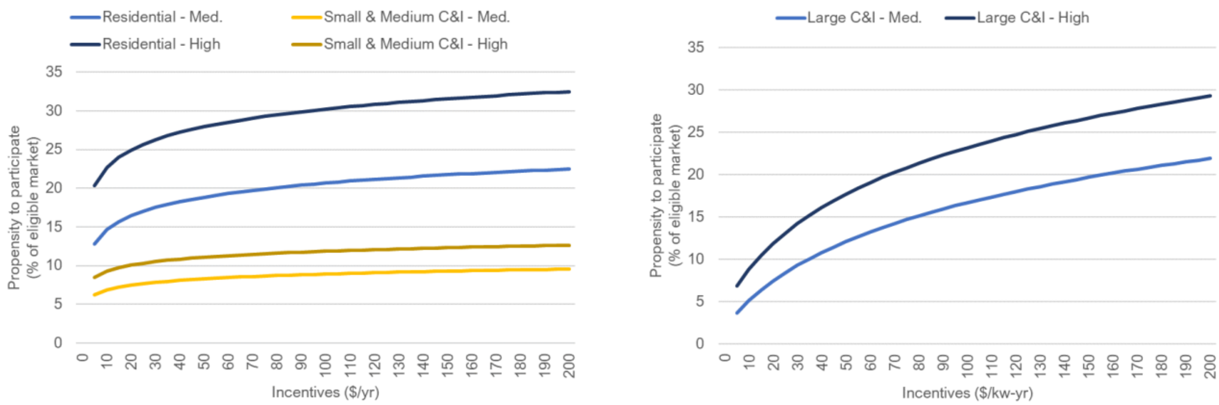
Table D-6: DER Participation Assumptions and Approach

DER Type	Assumption	Examples	Market/Program Participation Approach
A	**Not primarily driven** by financial benefits of market/program participation (i.e. DER functionality is a by-product).	Smart thermostats, smart appliances, or back-up generators are adopted by customers predominantly for other benefits (e.g. energy savings, comfort, resiliency)	Assess propensity to participate in markets based on incremental revenue/incentives and marketing efforts. Assume 100% of the DERs participate in the market (given that adoption is attributed to the market revenue).
B	**Somewhat driven** by financial benefits of market/program participation (i.e. DER functionality is a co-benefit)	Choice to install a smart EV charger or a smart water heater is partly influenced by the incremental benefits	
C	**Predominantly driven** by financial benefits of market/program participation (i.e. DER functionality is the key benefit)	Decision to adopt BTM solar or BTM storage is primarily based on financial returns a customer expects from net-metering, market revenue, or DR programs	

The team applied propensity curves to capture the portion of DERs likely to participate in the market or DER programs based on incremental revenues and barrier reductions. The propensity curves applied in the model are empirical relationships among key DR program features (incentives, events per year, and marketing) developed by the Lawrence Berkeley National Laboratory. They were developed based on a meta-analysis of hundreds of DR programs across North America, and provide a causal and quantifiable relationship between DR program participation and DR program features.

Two propensity curves are applied: one for residential segments and another for non-residential segments. The figures below present a subset of the propensity curves used in this study. Dunsky's model uses 30+ curves to account for changes in barriers, such as installation, required before the participant can join the program and marketing efforts.

Figure D-1: Sample of Propensity Curves (no installation – for example a Bring Your Own Device (BYOD) program) Used for DR Measure Participation

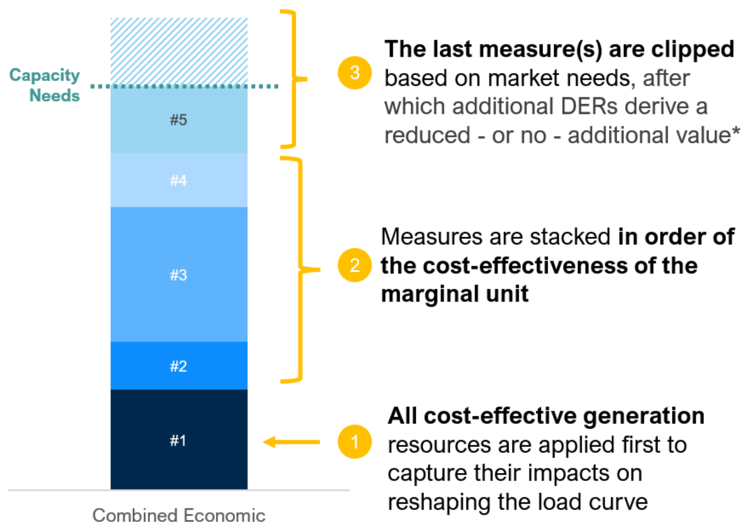


DR measures were modeled as aggregated market resources with the assumption that aggregators would provide customers with a participation / performance incentive equivalent to a portion of the market revenues, which was varied by scenario as described in Appendix E.

D.3 System Impacts

Applying the calculated DER adoption and market participation, DER measures are stacked considering their assumed dispatch characteristics, profile, and constraints (as identified under Technical and Economic Potential). Through an optimization process, the combined inter-measure impacts are captured to arrive at an assessment of the total achievable potential for DERs and their corresponding contributions to different system needs. Similar to the economic potential, in assessing the achievable potential, the model takes into consideration the marginal value and impact of incremental additions. Furthermore, the analysis takes into consideration the projected system needs for the various services considered in the study.

The approach used to stack measures is largely similar to that applied in the market-wide economic potential. Specifically, starting with the most valuable grid service (i.e. capacity), measures that passed the measure-level cost-effectiveness screening are stacked in order of cost-effectiveness up to the maximum system need *or* until no incremental cost-effective DER potential remained. However, unlike the market-wide economic potential, cost-effective load shaping measures (e.g. distributed generation) are applied first and new load shapes are computed. This allows for calculating the appropriate capacity contributions from incremental DER additions.



In addition to considering the total system needs, the study also captures the impact of incremental measure additions on load patterns and peak demand. Specifically, the interactive effects between measures and potential pre-charge or bounce-back effects are taken into consideration in assessing the impact and cost-effectiveness of incremental DER additions.

E. Scenario Assumptions

Increased electrification of key end-uses is seen as an important enabler of net-zero ambitions. It also has tremendous impacts on the electricity system; primarily through increasing forecasted electricity demand, changing load patterns, and accelerating system needs. The study considers the electrification of three key sectors:

- **Transportation:** The electrification of passenger and commercial fleet light-, medium-, and heavy-duty vehicles and buses.
- **Buildings:** The increased prevalence of heat pumps for space and water heating across the residential and commercial sectors.
- **Industry:** Fuel-switching of key industrial end-uses to electricity.

Detailed assumptions for each sector are highlighted in Volume II – Appendix E, however broadly the three levels of electrification modeled in the study reflect the following:

- **BAU:** The 2021 APO Reference Case is used as reflective of the forecasted load growth to be observed from modest levels of electrification.
- **BAU+**: The study assumes higher levels of electrification across all three sectors. The forecasted electrification of light-duty vehicles is in-line with the APO High Scenario and the Federal Government's Zero Emission Vehicle (ZEV) targets of 100% of new sales by 2035. Forecasts for other vehicle segments as well as the transportation and buildings sectors were based on projections from other jurisdictions, recent federal announcements and directionally align with the light-duty ZEV targets.
- **Accelerated**: The study assumes higher levels of electrification across all three sectors in-line with accelerating efforts to reach net-zero. For light-duty vehicles, the accelerated scenario aligns to Electric Mobility Canada's 2030 Vision, and other vehicle class forecasts are aligned with electrification progressions in other jurisdictions and directionally align with LDV forecasts. The forecasted electrification for buildings and industry is benchmarked against EPRI's Canadian National Electrification Assessment report, with adjustments.

Increased of electrification has multiple impacts of the system outlook and DER potential. Electrification impacts the technical potential for DERs directly by creating new opportunities for controllable loads. Electrified transportation, and space and water heating represent very large customer loads highly amendable to demand response. More important though, the forecasted rates of electrification have a significant impact on system outlook. Most prominently, under both the BAU+ and Accelerated scenario, an increase in both summer and winter peaks is observed; with Ontario facing a significant transition towards a winter peaking regime over the next decade. This change in system outlook and demand patterns also impacts wholesale energy prices observed across the scenarios.

E.1 Electrification

E.1.1 Transportation

E.1.1.1 Light-Duty Vehicles

The same trajectory was assumed for passenger and commercial fleet light duty vehicles. It was assumed that 25% of the market was commercial fleets, based on previous studies conducted by Dunsky, as well as other data sources.

Table E-1: Light-duty Vehicle Electrification Scenario Assumptions

Scenario	Assumption *% of fleet (% of new sales)*	Source
BAU	8% of LDVs by 2032 (19% by 2032)	APO Reference Scenario
BAU+	26% of LDVs by 2032 (76% by 2032)	Federal ZEV Target / APO High Scenario
Accelerated	50% of LDVs by 2032 (100% by 2032)	Electric Mobility Canada 2030 Vision

E.1.1.2 Other Vehicle Segments (i.e. Medium-duty, heavy-duty, buses)

Assumptions align with projections in other jurisdictions, recent federal ZEV targets, and directionally align with LDV forecasts.

Table E-2: Other Vehicle Segments Electrification Scenario Assumptions

Scenario	Vehicle	Assumptions *% of fleet (% of new sales)*
BAU	**MDV**	6% by 2032 (17% by 2032)
	HDV	2% by 2032 (6% by 2032)
	Buses	33% by 2032 (47% by 2032)
BAU+	**MDV**	17% by 2032 (33% by 2032)
	HDV	6% by 2032 (16% by 2032)
	Buses	59% by 2032 (82% by 2032)
Accelerated	**MDV**	23% by 2032 (50% by 2032)
	HDV	19% by 2032 (40% by 2032)
	Buses	70% by 2032 (100% by 2032)

E.1.2 Buildings

The electrification scenarios for buildings (space and water heating) considers heating fuel-switching as well as the portion of heat pumps that will displace existing cooling. The same directional trajectory was assumed for residential and commercial buildings.

Figure E-1: BAU Building Electrification Adoption (APO 2021)

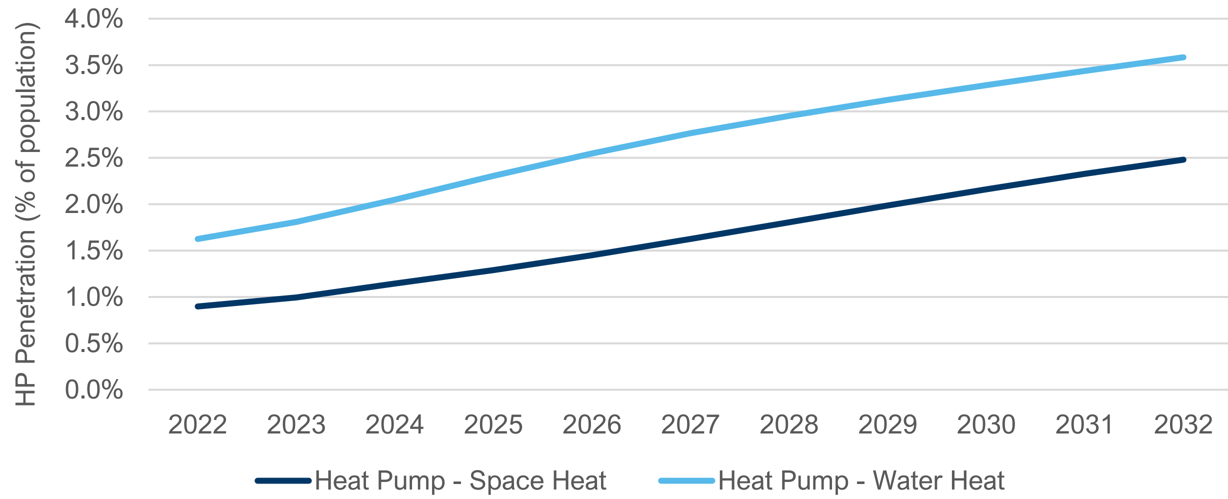


Table E-3: Building Electrification Scenario Assumptions

Scenario	Assumptions	Source
BAU	See graph above.	APO 2021 Reference Forecasts
BAU+	20% of buildings by 2032	IEA, Net Zero by 2050
Accelerated	40% of buildings by 2032	EPRI Canada Electrification, with adjustment

E.1.3 Industry Electrification

Industry electrification rates were determined from high-level benchmarks of projections of industrial end-use electrification from other studies. Projections were used to develop estimated compound annual growth rates of electricity use in the sector.

Table E-4: Industry Electrification Scenario Assumptions

Scenarios	Assumptions	Source
BAU	APO 2021 Reference Forecast	APO 2021 Reference Scenario
BAU+	1% CAGR in electric energy share of total industrial energy consumption	EPRI Canada Electrification (Baseline Scenario)
Accelerated	4.5% CAGR in electric energy share of total industrial energy consumption	EPRI Canada Electrification (Net Zero Scenario)

E.2 Carbon Pricing

- **BAU:** Carbon pricing increases steadily to $170/tonne by 2030 as per the Government of Canada's *Pan-Canadian Approach to Pricing Carbon Pollution*.[13] The performance standard is assumed to be maintained at the current levels of 370 tCO2/GWh.

- **BAU+:** Carbon pricing is maintained at $170/tonne by 2030, with the allowance benchmarking dropping to 0 tCO2/GWh

- by 2030

- **Accelerated:** Carbon pricing reaches $170/tonne by 2030 and is escalated further at $15/year, reaching $350/tonne by 2042. The allowance benchmark drops to 0 tCO2/GWh by 2030.

E.3 Market Compensation

To assess the benefits each DER can return to the DER provider (aggregator, developer, or electricity customer), market compensation assumptions were developed for each scenario, accounting for increased levels of compensation (compared to current market prices typically observed) and expanded market eligibility (under the BAU+ and Accelerated scenarios). The assumptions were developed to allow for greater DER participation and uptake in response to increased system needs under these scenarios. The specific compensation and eligibility assumptions applied under each scenario are provided in the following sections.

[13] Reference (accessed May 19, 2022): https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html. Note: All carbon prices presented are in nominal dollars.

E.3.1 Service Eligibility

Figure E-2: Service Eligibility by Measure Group

Retail / bill management benefit (impacts adoption decision-making)

		BAU	BAU +	Accelerated
BTM	Solar	Net-Metering (TOU / HOEP) [1]	No Change	No Change
	Storage	Arbitrage (TOU / HOEP) + ICI + Demand Charge (as applicable)		
FTM	DG	N/A		
	Storage	N/A		
DR		Arbitrage (TOU / HOEP) + ICI + Demand Charge (as applicable)[5]		

+ Compensation for service provision (impacts adoption decision-making and market participation)

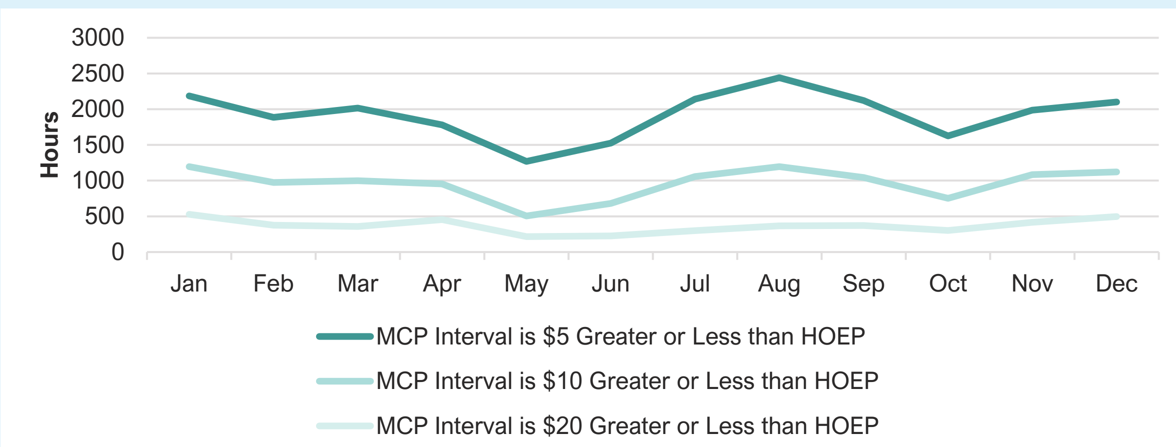
		BAU					BAU +					Accelerated				
		E	C	OR	RC	T&D	E	C	OR	RC	T&D	E	C	OR	RC	T&D
BTM	Solar	Compensated through retail (net-metering) [1]					Compensated through retail (net-metering)[1]					Compensated through retail (net-metering) [1]				
	Storage	✓[2]	✓	[3]			✓[2]	✓	✓[4]		✓	✓[2]	✓	✓[4]	✓[3, 4]	✓
FTM	DG	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Storage	✓	✓	✓	[3]		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
DR			✓	[3]				✓	✓[4]		✓		✓	✓[4]	✓[3, 4]	✓

[1] Qualitative discussion on VDER and alternatives to net-metering in report.
[2] Injected energy to be valued at HOEP for RPP customers.
[3] Technically eligible/capable, but barriers may prohibit participation; hence not considered in the study.
[4] Only for non-RPP customers. Customer would be assumed to switch over to MCP if they provide OR.
[5] Revenue from market participation / service provision – as opposed to retail/bill value streams (e.g. TOU arbitrage) are expected to be a significant driver of adoption of DR measures for most segments.

ANALYSIS OF THE VALUE OF FIVE-MINUTE DISPATCHABILITY

In Ontario, the Market Clearing Price (MCP) is set on a five-minute basis. For a variety of reasons – including demand and supply forecast error, unexpected outages and ramping constraints, among others – the MCP can experience volatility on an intra-hour basis. The project team conducted a statistical analysis of several representative days to identify and quantify the value of 5-minute dispatchability of DERs, with the goal of determining an "energy price adder" to include in the avoided cost model for DERs that could respond on a five-minute basis. While intra-hour price volatility occurs more commonly under certain circumstances, determining specific instances or situations where price volatility will be higher is extremely difficult. Various statistical analysis methods were used to attempt to determine when higher intra-hour price volatility will occur and therefore offer a potential value stream for 5-minute dispatchable DERs.

While intra-hour volatility in Ontario does happen, it is not materially present in most hours given Ontario's current supply mix. Ontario has a large fleet of flexible hydroelectric generators that are typically able to respond rapidly to intra-hour price volatility. As such, the intra-hour price volatility remains within $10 / MWh of the hourly average value for over 90% of all hours on the Ontario electricity market annually. When price volatility does occur, it typically happens in months when demand is highest and hydroelectric generators are more limited in their ability to respond to unexpected events. Intra-hour price spikes are also prevalent in April – when demand is low – due to the impact that freshet may have on hydroelectric operations. The following graph provides a breakdown of observed intra-hour price volatility by month.



No statistically significant circumstances were identified using historic MCP data over the past four years. This is not surprising since Ontario has been relatively oversupplied over the past decade and has not experienced significant real-time price volatility. Further, many of the system operation tools and changes to the tools under consideration through the IESO's Market Renewal Program work to minimize or eliminate intra-hour volatility through flexibility mechanisms and proactive operating constraints. Future value for DERs for 5-minute dispatchability may exist, but will depend significantly on future supply mix, demand growth and system operation tools used to schedule and dispatch resources. Based on this analysis, no 5-minute energy price adder was incorporated into the avoided cost model, but the IESO may benefit from conducting further research to better quantify the value of 5-minute dispatchability to the system.

E.3.2 Capacity Compensation

Current capacity market prices typically represent a fraction of the assessed avoided costs of capacity. Thus, various levels of compensation for capacity providing resources were developed, assuming that as capacity needs increase, the market price (or other procurement mechanisms) would increasingly align the capacity service compensation rates with the system's avoided cost of capacity. The specific details are as follows:

- **BAU:** Capacity Auction projections (equivalent to 30-40% of the avoided cost capacity value defined in the economic potential model).
- **BAU+:** 70% of the avoided cost capacity value defined in the economic potential model.
- **Accelerated:** 100% of the avoided cost capacity value defined in the economic potential model.

E.3.3 Barrier Reduction

While some barriers can be specifically addressed in the modeling (such as service eligibility) other barriers are more diverse or qualitative in nature (i.e. customer awareness, building code or zoning requirements, developer discount rates etc.). To account for their combined impact on the adoption projections, the model is calibrated to past market uptake/participation, and representative barrier levels are established to reflect current market conditions. Based on this, **two factors were then considered to capture the impacts of barrier reductions:**

- **Step barrier reduction:** Barrier levels are used to reflect the propensity of a market participant to participate in a DER program given certain revenues. For this study, barriers were calibrated using existing participation in the HDR program under the BAU scenario. Additionally, Class A and Class B non-RPP customers were assumed to have lower barriers than RPP customers as they have operational knowledge and experience minimizing their energy costs. These barriers were then slightly reduced between BAU and BAU+ and furthermore between BAU+ and Accelerated to account for efforts to alleviate barriers that could constrain DER participation (e.g. aggregation limits, metering requirements, etc.).
- **Increase in pass-through from aggregators to contributors:** An increase in the percentage of market revenues passed on from aggregator to contributors was used as a proxy for alleviating market barriers that could allow aggregators to reduce their take-back amounts.

Figure E-3: Percentage of Revenues by Scenario and Customer Type

% of Revenues	BAU	BAU+	Accelerated
Residential and Small C&I	35%	50%	75%
Large C&I and Industrial	75%	80%	90%

E.4 Technology Costs

Technology costs were varied by scenario for key technology categories that are expected to experience significant cost declines over the next decade (e.g., solar PV, storage, V2B/G). These scenarios reflect more aggressive declines in technology costs than what is projected in the base case and/or the consequence of funding streams/incentives that reduce upfront installation costs (e.g., federal grants for residential solar).

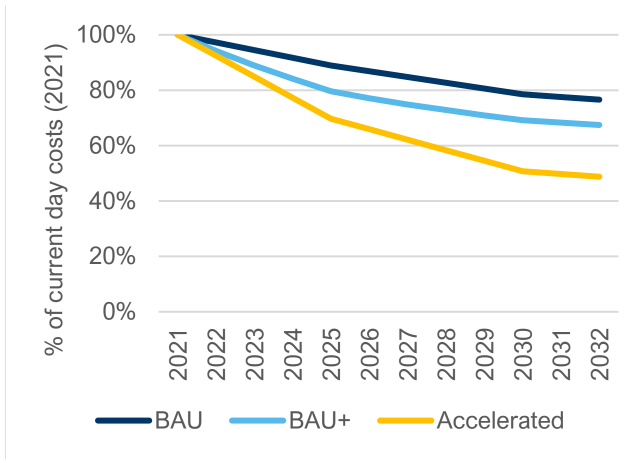


Figure E-4: Energy Storage Cost Declines over Study Period

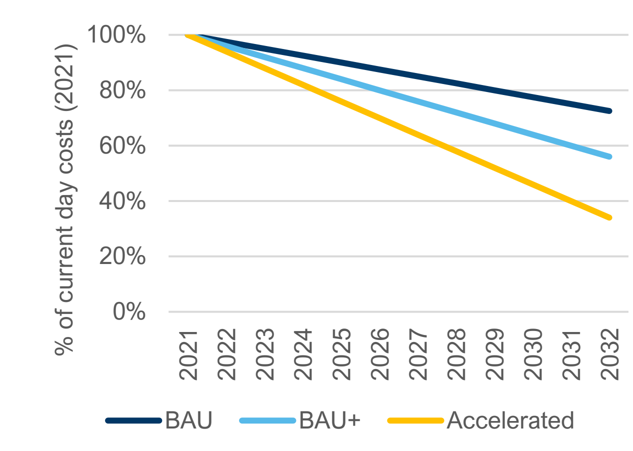


Figure E-5: Electric Vehicle Smart Chargers Cost Declines Over Study Period

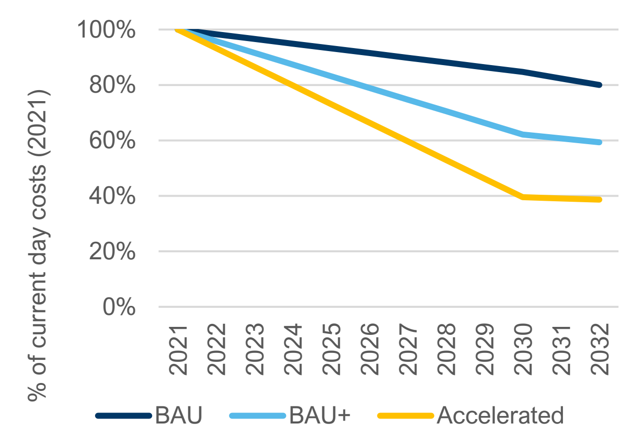


Figure E-6*: Residential Solar Cost Declines Over Study Period.*

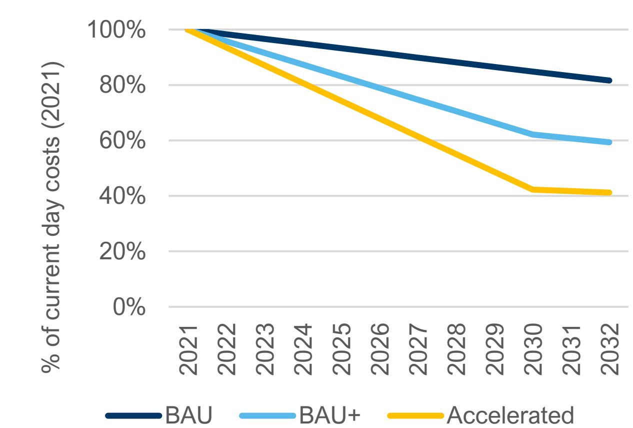


Figure E-7*: Commercial and Industrial Solar Cost Declines Over Study Period*

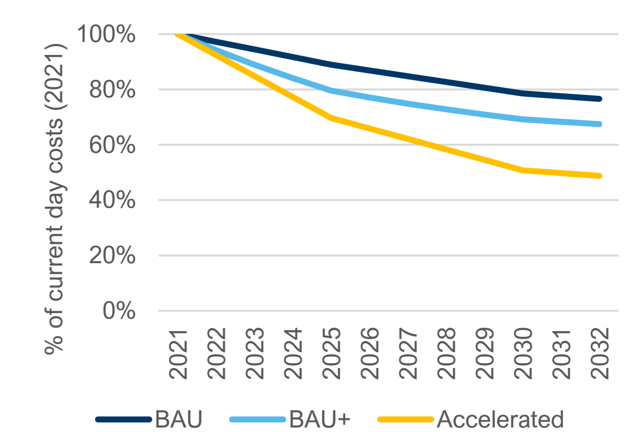


Figure E-8: Residential Storage Cost Declines over Study Period

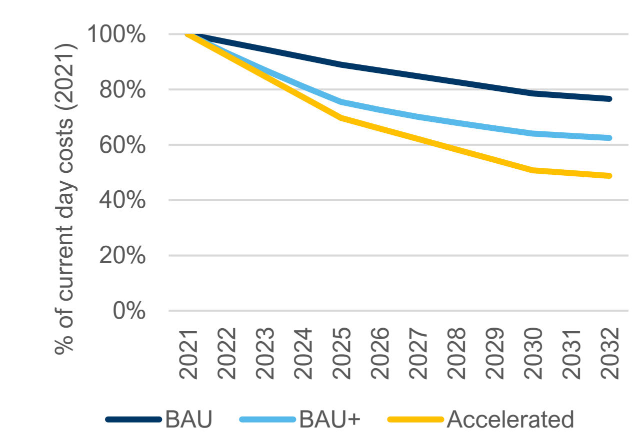


Figure E-9: Commercial and Industrial Storage Cost Declines Over Study Period

Table E-5: Solar Current Day Costs by Segment

Technology	Segment	Current day costs (2021) $/kW
Solar, Residential	All	2,500
Solar, Commercial	Office	2,250
	Other Commercial	2,066
	Non-food retail, Restaurant, Hotel	1,950
	Large non-food retail, Food retail, Hospital, Nursing Home, School, Warehouse	1,650
	Large Office, Large Hotel, University & College	1,567
Solar, Industrial	All	1,567

Table E-6: Storage Current Day Costs by Segment

Technology	Segment	Current day costs (2021) $/kWh
Storage, Residential	All	1,126
Storage, Commercial	Office	1,031
	Other Commercial	826
	Non-food retail, Restaurant, Hotel	738
	Large non-food retail, Food retail, Hospital, Nursing Home, School, Warehouse	622
	Large Office, Large Hotel, University & College	534
Storage, Industrial	All	534

The assumptions were developed based on cost projections compiled by Dunsky from key industry resources (e.g. NREL ATB, IEA, BNEF) and generally follow the trends described in the table below.

Table E-7: Technology Cost Scenario Assumptions

Scenarios	Cost Decline	Source
BAU	2 – 3% annual decline in costs	Dunsky database complemented with key industry resources (e.g. NREL ATB, IEA, BNEF)
BAU+	3 - 5% annual decline in costs	
Accelerated	5 – 7% annual decline in costs	

E.5 Supply Resource Mix

Across the three scenarios, different resources were assumed to be the marginal capacity resources used to set the avoided capacity costs. The supply resource mix assumptions were developed based on a mixture of planning criteria (e.g., resource adequacy objectives), policy direction (e.g., lower carbon intensity of electricity supply over next decade) and comparative project economics (i.e., renewable generation generally is the lowest cost energy resource for new supply). The supply mix was developed with input from the IESO and reflects the unique nature of the Ontario electricity sector (e.g., hybrid market design). The BAU scenario reflects reasonable procurement of transmission connected resources by the IESO to meet resource adequacy needs and other planning criteria. Under the BAU+ and Accelerated scenarios, the resource supply mix only assumes committed and planned resources. An objective of the Accelerated scenario is to assess the capability of DERs under a scenario of constrained transmission-connected resource development. The table below summarises the key assumed resource buildouts over the study period.

Table E-8: Assumed Capacity Resource by Scenario

Scenarios	Assumption	Value ($2021)	Source
BAU	Simple-cycle gas-fired generation facility (SCGT)	$605/MW-day ($2021) Escalated at 2%/year	IESO
Accelerated / BAU+	Calculated net CONE for Renewables + Storage Solution	$675/MW-day ($2021) Escalated at 2%/year	Project team estimate based on industry projections and estimated market revenues.

Additionally, the table below summarizes the supply mix assumptions. The detailed supply resource mix values are highlighted in Table C-4.

Table E-9: Supply Resource Mix Scenario Assumptions

Resource	BAU	BAU+	Accelerated
Nuclear	Pickering Nuclear Generation Station (NGS) is retired in 2024/2025 Ontario's nuclear refurbishment program at Darlington NGS and Bruce Power completed on schedule New Small Module Reactors (SMRs) installed in 2030s	Pickering Nuclear Generation Station (NGS) is retired in 2024/2025 Ontario's nuclear refurbishment program at Darlington NGS and Bruce Power completed on schedule Multiple Small Module Reactors (SMRs) installed in 2030s	Pickering Nuclear Generation Station (NGS) is retired in 2024/2025 Ontario's nuclear refurbishment program at Darlington NGS and Bruce Power completed on schedule Multiple Small Module Reactors (SMRs) installed in 2030s
Gas-Fired	Practically all gas-fired generation remains in service after contract expiry No new gas-fired generation Expectation of low carbon fuel adoption over time (e.g., Renewable Natural Gas). Assuming low carbon fuels will be priced at the price of gas + carbon tax	Existing gas-fired generation remains for operational and reliability purposes, increase in conversion and usage of lower carbon intensive fuels compared to BAU	Practically all gas-fired generation remains in service over the forecast horizon No new gas-fired generation
Hydroelectric	No changes to transmission connected hydroelectric generation	No changes to transmission connected hydroelectric generation	No changes to transmission connected hydroelectric generation

Resource	BAU	BAU+	Accelerated
Non-Hydro Renewables	New transmission connected renewable generation (i.e., wind and solar generation) developed in the late 2020s and through the 2030s	Expanded growth of transmission connected renewable generation in late 2020s and 2030s	Existing renewables continue to operate over the forecast horizon New renewables + storage procured to meet 1,000 MW UCAP target for 2021 AAR
Storage	Transmission connected storage development in the mid-2020s and through the 2030s	Multiple large-scale transmission connected storage developments starting in mid-2020s with consistent growth in 2030s	New renewables + storage procured to meet 1,000 MW UCAP target for 2021 AAR Oneida Energy Storage (250 MW) in service by 2026
Import	Potential short-term firm import agreements, limited by intertie capacity	Potential short-term firm import agreements, limited by intertie capacity	New intertie capacity to PJM (i.e., Lake Erie Connector)

DR and storage measures can shift consumption from times when high-emitting resources are on the margin to times when lower-emitting resources are on the margin, but with storage incurring a roundtrip efficiency penalty that would somewhat hamper the overall carbon benefits. However, for all scenarios, in the latter years of this study, due to high load growth, gas generation appeared on the margin nearly 100% of the time, severely limiting the carbon-abatement opportunities of DR and storage (relative to a counterfactual hypothetical circumstance where the marginal generating resources alternated between gas and non-emitting generation such as renewables or nuclear). See the table below for hours of the year where gas-fired generation or imports are on the margin.

Table E-10: Hours/Year of Gas Fired Generation or Imports on the Margin

Year	BAU	BAU+	Accelerated
2023	7,880	8,207	8,351
2024	6,864	7,358	7,821
2025	7,747	8,192	8,489
2026	8,216	8,631	8,725
2027	8,120	8,517	8,728
2028	7,940	8,556	8,766
2029	8,123	8,676	8,759
2030	8,076	8,645	8,760
2031	8,070	8,669	8,760
2032	7,797	8,623	8,784

F.Measure Screening and Approach

See data file "*Appendix F - Measure Screening and Approach.xlsx*"

G. Detailed Results and Inputs

See data file "*Appendix G - Detailed Results.xlsx*"