# IESO Local Achievable Potential Study Toronto Planning Region

DRAFT REPORT

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ICF

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| Acronym | Full Form |
|---|---|
| **BCA** | Benefit-Cost Analysis |
| **BESS** | Battery Energy Storage Systems |
| **BCR** | Benefit-Cost Ratio |
| **CET** | Cost-Effectiveness Test |
| **DEER** | Database for Energy Efficiency Resources |
| **DER** | Distributed Energy Resource |
| **DR** | Demand Response |
| **eDSM** | Electricity Demand Side Management |
| **EE** | Energy Efficiency |
| **EV** | Electric Vehicle |
| **HVAC** | Heating, Ventilation, and Air Conditioning |
| **IESO** | Independent Electricity System Operator |
| **IRRP** | Integrated Regional Resource Planning |
| **MPAC** | Municipal Property Assessment Corporation |
| **MTS** | Municipal Transformer Station |
| **MURB** | Multi-unit Residential Building |
| **NC** | New Construction |
| **NPV** | Net Present Value |
| **NREL** | National Renewable Energy Laboratory |
| **PAC** | Program Administrator Cost |
| **PNNL** | Pacific Northwest National Laboratory |
| **PV** | Photovoltaic |
| **RET** | Retrofit |
| **ROB** | Replace-on-Burnout |
| **TS** | Transformer Station |
| **TRM** | Technical Reference Manual |

# 1 INTRODUCTION

The Independent Electricity System Operator (IESO) commissioned ICF Consulting Canada, Inc. (ICF) to carry out Local Achievable Potential Studies for the Ottawa and Toronto regions, aimed at identifying the 20-year (2025–2045) potential for energy and peak demand savings from energy efficiency (EE), demand response (DR) and behind-the-meter distributed energy resources (DERs). The EE, DR, and DERs together are referred to, hereinafter in this document, as electricity demand-side management (eDSM). This study will support regional electricity planning as well as design, targeting, and evaluation of future customer programs by producing highly granular forecasts down to the transformer station (TS) level.

ICF developed localized load forecasts under both business-as-usual and high electrification scenarios to serve as baselines for assessing eDSM impacts. To achieve this, ICF employed a highly detailed, bottom-up approach centered around its DER Insight platform—an advanced, cloud-based analytics tool. The process began with project planning and a structured data collection phase, including information from IESO, publicly available datasets, and the Municipal Property Assessment Corporation (MPAC). The data formed the basis for creating "digital twins"—sophisticated, physics-based models that simulate energy behavior at the individual building level. These digital twins were calibrated using local climate, building characteristics, and historical energy use in the buildings to establish a baseline energy profile. ICF then ran simulations to evaluate the impact of various eDSM measures, such as EE upgrades, electrification technologies, solar photovoltaic (PV), battery storage, and DR. Each measure was assessed for its technical feasibility, economic value, and likelihood of adoption. The results were then aggregated to the TS level and analyzed to generate comprehensive forecasts of technical, economic, and achievable potential. This rigorous modeling process ensures IESO receives robust, actionable insights tailored to local infrastructure and customer needs, supporting both immediate planning and long-term strategic development.

This report details the methodology and results for the Toronto planning region. The report is laid out as follows:

- Section 2 provides details of the ICF methodology to determine the achievable potential, traversing the steps of load forecasting measure list development and generating technical and economic potential as intermediate deliverables. It also provides details of the inputs and assumptions, and the development of digital twins that serve as the foundation for the estimation of potential.
- Section 3 presents the draft results of the study—mainly summer and winter demand (MW) savings broken down by sector and end use category within the Toronto planning region.

**Please note the presented draft results are inclusive of the significant quantities of new peak demand savings from eDSM programs that are already included in the Toronto IRRP demand forecasts. For the purposes of electricity system planning, the planned savings**

**must be deducted from the achievable potential results to establish the opportunity for additional eDSM.**

The appendices provide Microsoft Excel spreadsheets of measure characterization as well as additional details of inputs and assumptions.

# 2 METHODOLOGY

## 2.1 Summary

ICF used its proprietary analytics platform DER Insight to conduct the local achievable potential study for the Toronto Planning Region. DER Insight is a sophisticated analytics platform developed to support integrated planning of eDSM programs. It leverages extensive datasets, advanced physics, machine learning–based analytics, and flexible visualizations to model customer programs. This tool enables utilities, system planners, and policymakers to quantify potential energy and demand savings from measure adoption across their service territories.

In line with the objectives of the study, the following high-level process flow diagram (**Figure 1**) guided the implementation of the work within DER Insight.


*Figure 1. Technical Approach Process Flow*

The first step[1] involved developing the digital twins of the buildings within the Toronto Planning Region. Digital twins are the closest approximation of the real buildings that can be simulated to determine energy consumption. These digital twins helped establish the baseline energy and demand usage, by sector and end use. Applying the forecasting parameters to these digital twins produced the load forecast for the territory at the substation level, and this constituted the second step in the process.[2] With the baseline and load forecast estimated, we move to develop a list of measures that will determine the savings potential for the study period (described in Appendix A). The measure list consists of programs comprising of EE, DR, and DERs. The final step involved estimating the technical, economic, and achievable potential and generating the annual savings for energy and demand, at the transformer station level, by program and end use for all sectors.

[1] Note that the digital twin approach is only applicable to the residential and commercial sectors, since no prototypical models are available for the industrial sector.

[2] Due to the absence of digital twins in the industrial sector, we leveraged MPAC data to evaluate the distribution of industrial building types at each substation and proportionally allocated the industrial load based on that distribution.

A detailed methodology, along with the inputs and assumptions, is described in the following subsections.

## 2.2 Data Inputs and Digital Twin Framework

### 2.2.1 Data Sources and Inputs

DER Insight relies on structured input templates for ingesting essential planning data. These inputs are classified into three types:

1. **Utility and Financial Non-Measure Inputs.** Inflation rates, discount rates, economic growth assumptions, line losses, avoided energy and demand costs, retail rates.
2. **Measure Data.** Comprehensive specifications for eDSM measures, including measure type, technology class, costs, incentives, measure life, and applicability conditions.
3. **Program Data.** Historical and operational information about programs.

For this study, DER Insight input data are primarily obtained from either IESO or Toronto Hydro, and any gaps were filled in with publicly available data and/or ICF internal databases[3] guided by ICF expertise and in discussion with IESO and Toronto Hydro. Sources for data type 1 are provided in Table 1 below, while the sources for measure data, by sector, are provided in Section 2.4. Values for all parameters in Table 1 are provided in Appendix B.

*Table 1. Source List for Utility and Financial Non-Measure Inputs*

| Parameter | Sources |
|---|---|
| Study Start and End Years | IESO |
| Utility Company Real Discount Rate | IESO (Weighted Average Cost of Capital) |
| Inflation Rate | IESO |
| Reserve Margin[4] | IESO's Reliability Outlook—Planning and Forecasting |

[3] ICF's internal databases are the result of extensive research and continuous refinement, grounded in a diverse set of credible sources. They are built using information from technical reference manuals across multiple jurisdictions, insights gained from past and ongoing implementation projects, and findings from evaluation, measurement, and verification studies and potential studies. In addition, the databases are informed by ICF's in-house research and development efforts, including emerging technology assessments and pilot program evaluations. By integrating these inputs with utility filings, regulatory guidance, and industry best practices, ICF ensures that its internal databases are comprehensive, accurate, and reflective of real-world conditions—serving as a critical foundation for robust program design, savings estimation, cost-effectiveness analysis, and load forecasting.

[4] Reserve margin is the additional capacity (usually specified as percentage of peak load) that utilities must maintain above forecasted peak demand to ensure system reliability. When demand-side management reduces peak demand, it also reduces the megawatts of reserve capacity needed. Including the reserve margin in the analysis ensures that

| | |
|---|---|
| Avoided Costs | 2024 Annual CapEx Capacity Costs, IESO<br>2024 Annual Avoided Costs, IESO<br>Planned Transformer Upgrade Costs[5] |
| Retail Rates | Toronto Hydro Residential and Commercial Tier 1 Rates: Residential and Commercial |

***Scenarios***

The study was modeled for two scenarios, reference and high electrification, which align with the corresponding Integrated Regional Resource Planning (IRRP) demand scenarios provided by Toronto Hydro:

- **Reference Scenario.** The base load for this scenario shows a steady increase in electricity use based on current policies, steady growth of electrified heating (i.e., Business as Planned targets in TransformTO[6]), a trending historical electric vehicle (EV) adoption, and low/steady growth of data centers.
- **High Electrification (HE) Scenario.** The baseline load in this scenario aims to achieve the TransformTO net-zero targets for buildings by 2040, higher adoption of EVs (30% adoption by 2030 and 100% by 2040), and elevated growth rate of data centers.

***Elements of Analysis***

Apart from the inputs described in the above subsection, the following details provide additional information on the assumptions, definitions, and metrics used for this study.

- **Reported Savings.** All the savings numbers (GWh and MW) reported are at the meter (i.e., do not factor in the line losses and reserve margin components). Reporting numbers at the meter is considered the most appropriate for understanding non-wires potential.
  - For the benefits calculation in the benefit-cost analysis (BCA) tests, though, line losses and reserve margin components are factored in since avoided energy and capacity costs are calculated at the system level..
- **Demand Savings Calculation.** Demand savings for all eDSM measures are calculated using DR event hours identified from the 2024 IESO system peak period. Per-measure savings are based on first-year load shapes (from digital twin simulations or deemed values) and are

the avoided capacity value of demand-side management measures reflects both the direct peak load reduction and the associated reserve requirement, providing a more accurate estimate of system capacity savings.

[5] ICF assumed a 1-year deferral period, 5 years into the study, and the achievable megawatt savings from the respective substations to calculate the avoided transmission costs and applied the costs to the rest of the study period as well. The costs provided by IESO were $20 million for Mandy autotransformers (John, Strachan, and Copeland stations) and $60 million for Dufferin station.

[6] TransformTO is the City of Toronto's Net Zero Strategy aimed at achieving net-zero greenhouse gas emissions by 2040. It emphasizes community-wide efforts focused on electrifying transportation, improving building EE, and adopting renewable energy sources.

held constant across the study period. Since developing future 8760 profiles is not within the scope of this work, the same event hours and savings are applied each year. The only factor that changes is the end-use intensity.

- **DR Events.** Based on highest average IESO loads, the peak period for this study is defined as a 4-hour window for summer (HE 16-19) and a 5-hour window for winter (HE 15-19). The 10 DR events are called within this peak period window for a maximum of 3 hours at a time.
- **Delivery Types.** The following three delivery types were included in the study for EE programs.
  - **Retrofit (RET).** A measure category that includes the addition of an efficiency measure to an existing facility such as insulation or air sealing to control air leakage.
  - **Replace-on-Burnout (ROB).** A measure category where the equipment is replaced on failure or where a utility EE program has not influenced the customer decision to replace.
  - **New Construction (NC).** Efficiency measures in NC or major renovations, whose baseline would be the relevant code or standard market practice.

### 2.2.2 Digital Twin Framework

After gathering the inputs, ICF began the development of digital twins. Each building in the utility territory was represented using a digital twin[7]—a virtual model capturing the building's physical attributes, end-use equipment, energy consumption profile, and location-specific characteristics. These digital representations were guided by prototypical building energy simulation models from the National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL), building data from MPAC datasets, postal code mappings to transformer station/municipal transformer station (TS/MTS) zones, and energy/demand usage data for 2024.

The development of the digital twins for the Toronto Planning Region involved a four-step process (**Figure 2**): (1) preparing the building stock using prototypical building types from NREL and PNNL, (2) processing and integrating building data from the MPAC dataset as well as energy/demand usage data to match the buildings to the digital twin models, (3) running ResStock[8] and ComStock[9] building energy models to simulate the baseline load after

[7] If there are multiple buildings that have similar characteristics, they could potentially be mapped to the same digital twin.

[8] ResStock is a modeling tool developed by NREL to analyze the potential of residential EE improvements and packages on U.S. residential building stock. It combines large public and private data sources, statistical sampling, detailed building simulation, and data on housing characteristics, energy use, and regional variations to assess EE opportunities, RET impacts, and policy scenarios at scale (https://resstock.nrel.gov/).

[9] ComStock is a tool developed by NREL to model the energy performance of commercial buildings in the United States. It uses data on building characteristics, energy use, and regional differences to assess EE, RET opportunities, and the impact of policy changes (https://comstock.nrel.gov/).

customizing them to the climate zone of Toronto, and (4) calibrating and refining the models and validating them against the existing energy usage data.

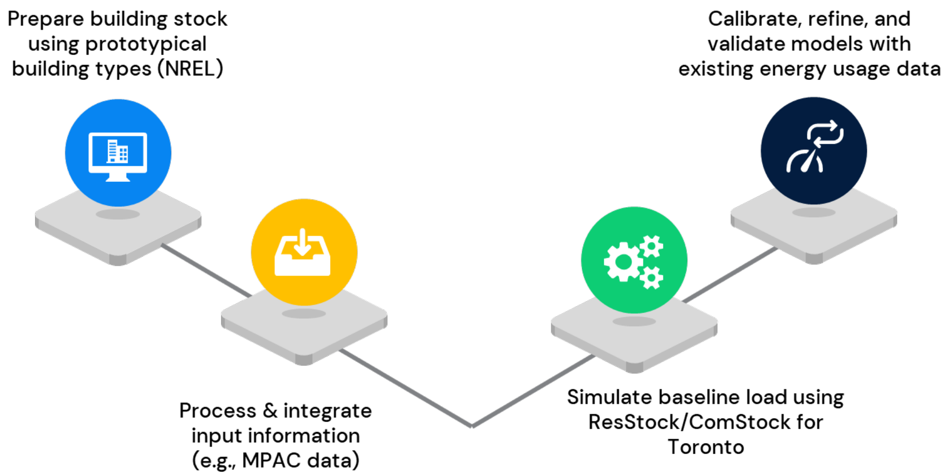


*Figure 2. Digital Twin Workflow*

The sources involved in obtaining data for modeling the digital twins are shown in **Table 2**.

*Table 2. Data Sources for Digital Twin Modeling*

| Data Information/Type | Sources |
|---|---|
| Building Prototypes | NREL's ResStock (2023) and ComStock (2024) prototypes |
| | PNNL's Residential Prototype Buildings |
| Input Data for Digital Twins | MPAC data (building characteristics such as heating type, floor area, postal code, etc.) |
| | IESO Residential End-Use Survey Results |
| | U.S. Energy Information Administration (EIA) Manufacturing Energy Consumption Survey (2018) |
| | EIA Residential Energy Consumption Survey (2020) |
| | EIA Commercial Buildings Energy Consumption Survey (2018) |
| Baseload Measure List | IESO Measures and Assumptions List |
| | 2022 IESO Achievable Potential Study |
| | 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study |
| Calibration and Validation Data | Historic Load Distribution Company Load data and Forecasts |

## 2.3 Baseline Construction and Load Forecasting

The baseline load forecast models the future energy use across the service territory in the absence of any new eDSM efforts. The load forecasting methodology adopted by ICF involved the following high-level steps to estimate the base year (2024) and long-term (2025–2050) electricity demand across residential, commercial, and industrial sectors:

- Use data from multiple sources, listed in Table 3, to
    - Obtain the core inputs such as MW forecasts for electrified heating, EV, data centers, and connection requests
    - Refine the inputs such as building counts and multi-unit residential building (MURB) reclassification from commercial to residential sector
- Convert peak MW forecasts into annual kWh forecasts using sector-specific coincidence and kW/kWh ratios obtained from the digital twins, and subsequently disaggregating by substation and end use
- Perform necessary adjustments to align the digital twin forecasts and the IRRP forecasts and calibrate the final numbers to historical load as well as IRRP forecasts

This methodology ensured a high-resolution, scenario-driven forecast framework suitable for strategic planning.

*Table 3. Data Sources for Baseline Construction and Load Forecasting*

| Data Information / Type | Sources |
|---|---|
| Sector-Based Energy Use Projections and End-Use Level Split | IESO Demand Forecast, by Region and by Sector |
| Ontario Energy Board (OEB) Energy and Demand Forecasts | OEB-posted annual billings and energy-related determinants for customers and connections for Toronto Hydro |
| Electricity Demand Forecast Inputs | Toronto Hydro's IRRP Reference and High Electrification Case Demand Forecasts for Summer and Winter |
| Substation-Level Load Profiles | Toronto Hydro Hourly Load by Station |
| Customer Classification | Toronto Hydro 2023 Customer Segmentation |
| Building Characteristics | MPAC |
| Geospatial Demand Allocation | Digital Twin Mapping Results by Substation<br>Digital Twin New Construction Residential Customers |
| EV Coincidence Factor | IESO Peak Tracker<br>Electric Vehicle Infrastructure Toolbox |

The following subsections provide details on some of the nuances of base year load forecast for each sector. They also provide further information on the approach for forecasting the load for the study period for the two scenarios, calibration of forecasts and incorporation of various components of the IRRP forecasts.

### 2.3.1 Base Year Load Construction

***Residential***

Using digital twin development summary outputs for the Toronto Planning Region (described in Section 2.2.2), ICF identified the total number of residential households, categorized by building type (e.g., single-family, multifamily).

To accurately account for MURBs, the team identified those billed under commercial retail rates and used MPAC data to determine the true number of homes within these buildings. ICF then adjusted the residential annual kWh by reallocating the residential portion of energy currently captured under commercial and industrial (C&I) rates, primarily from MURBs billed commercially. This reallocation, guided by MPAC data, ensured energy consumption from residential units was correctly assigned to the residential sector.

Additionally, ICF refined per-home annual kWh consumption values using Toronto-specific digital twins. For 2024, ICF analyzed historical residential consumption data from the OEB demand and revenue public filing. Starting with Natural Resources Canada's average Ontario annual kWh per home value, ICF calibrated the estimate using Toronto-specific digital twins. Household counts and annual kWh for 2024 were then estimated by applying IESO zonal forecast proportions.

The final estimate of true residential energy consumption was calculated as:

*True Res Annual kWh = Res Annual kWh (from OEB data) + Res Annual kWh portion of C&I*

Finally, ICF allocated household counts and annual kWh by building type to Toronto Hydro substations using summary outputs from the digital twin development and a Python-based forecasting tool. Household counts were distributed based on digital twin summary outputs, which mapped each representation to its corresponding substation. Annual kWh was then allocated using a Python-based forecasting tool that processed energy usage data for digital twins to estimate demand at the substation level.

***Commercial***

To calibrate commercial annual kWh at the substation level, ICF used the hourly load by substation data. The team calculated total substation kWh in 2022 and extrapolated values for 2024 using IESO forecasts. C&I annual energy usage at each substation was estimated by subtracting residential annual kWh load from the total substation energy.

Commercial sector digital twins were simulated to produce 8,760-hour energy usage profiles for each building. From these profiles, ICF derived annual energy consumption and peak hourly demand to calculate sector-specific kWh/kW ratios. These ratios were then applied to estimate substation-level demand (kW) across sectors.

Additionally, customer segmentation data from Toronto Hydro were used to determine kVA percentage splits and sectoral allocations. The total C&I annual kWh was split into commercial and industrial components based on peak kW proportions. The commercial energy consumption of each substation was then calibrated so the total across all substations aligned with the 2024 total from OEB data.

Finally, using the digital twin summary outputs for the commercial sector and substation-level commercial energy consumption, ICF further disaggregated the energy usage by building type. Building type allocation to substations was based on the digital twin summary outputs, while a Python-based forecasting tool was used to allocate annual kWh by processing energy usage data from each digital twin to estimate demand by building type at the substation level.

***Industrial***

For the industrial sector, ICF based its evaluation of potential on total annual kWh consumption, recognizing the wide variability in facility size, operational processes, and energy intensity. In the absence of digital twins (i.e., prototypical building energy models) or detailed facility-level data, the modeling approach relied entirely on energy usage metrics rather than specific facility characteristics.[10]

In parallel to the development of commercial energy consumption of each substation (described in the Commercial section above), the industrial energy consumption at the substation level was also calculated. ICF disaggregated the substation-level industrial annual kWh into subsectors using distribution patterns derived from MPAC industrial data queries. This approach ensured a detailed and accurate representation of energy use across Toronto Planning Region

### 2.3.2 Forecasting Components

This analysis builds its load forecast upon the IRRP framework by layering incremental demand components—New Construction, Electrified Heating, EVs, and Data Center loads—on top of the existing base load, thereby aligning with the IRRP Reference and HE scenarios to reflect regional demand growth and electrification trends.

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[10] This also implies that there will be no "customer count" metric in the outputs because all modeling is based on kWh energy usage profiles at the subsector level.

### *New Construction*

Forecasts for new building counts and energy usage are derived from the **Connection Request** end-use forecasts provided in the IRRP. ICF disaggregated the Connection Request MW forecasts by sector and substation using Summer MW forecasts from IRRP data. These forecasts were allocated to the residential, commercial, and industrial sectors at each substation by applying kVA percentage splits sourced from the customer segmentation data. This approach ensured sector-specific distribution aligned with Toronto Hydro's customer segmentation.

To convert sectoral peak MW values to annual kWh at the substation level, ICF applied sector-specific kW/kWh ratios. For the residential and commercial sector, these ratios were calculated as the weighted average of kW and kWh values derived from the digital twin mix. For the industrial sector, the ratio was determined using the sector's annual consumption and the peak demand, given the absence of detailed digital twin models. ICF then allocated the calculated sectoral annual kWh to new construction. This energy was distributed across building types within each substation using proportional breakdowns observed in the 2024 base year load. This method preserved consistency with historical patterns while accommodating projected growth.

For the period 2025–2029, ICF estimated new construction building counts by dividing the sectoral annual kWh values by digital twin–based average building energy usage figures. For the years 2030–2050, the connection request MW forecasts remained constant, which was deemed unrealistic for long-term planning. To address this limitation and produce a more representative projection of new construction growth, ICF extrapolated the average annual increase in building counts observed between 2025 and 2029. This increment was then applied linearly to each year from 2030 to 2050. By doing so, ICF introduced a scalable and dynamic growth trajectory that better reflects expected development trends over the long term.

### *Electrified Heating*

ICF began by allocating the electrified heating summer MW forecast by sector and substation, under the assumption that summer electric heating demand is solely due to water heating, as space heating is not typically used during this season. Residential and commercial water heating summer kW values were derived from digital twin outputs, while industrial values were estimated based on commercial-to-industrial ratios from customer segmentation data. These sectoral kW values were used to calculate each sector's percentage share of total water heating demand, which was then applied to the IRRP electrified heating summer MW forecast. Annual water heating kWh was estimated using established kW/kWh ratios.

For winter, the electrified heating MW forecast includes both water and space heating. Residential and commercial space heating kW values were again sourced from digital twin outputs, and industrial values were estimated using the same ratio-based method. Water and space heating kW values were combined by sector and substation to determine each sector's share of total winter heating demand. These shares were applied to the IRRP electrified heating winter MW forecast and converted to kW.

To separate winter water heating from space heating, ICF estimated winter water heating MW by multiplying annual water heating kWh by winter-specific kW/kWh ratios. This value was subtracted from the total winter MW forecast to isolate space heating MW. A similar conversion was applied to estimate annual space heating kWh.

Finally, total annual electrified heating kWh was calculated by summing water and space heating kWh by sector and substation. These totals were then distributed across existing and new construction building types using proportions from the base case load forecast.

***EVs and Data Centers***

ICF converted the EVs summer MW forecast from the IRRP forecasts to obtain the corresponding annual kWh by assuming an EV coincidence factor for peak load. The EV coincidence factor was determined using U.S. Department of Energy Alternative Fuels Data Center's[11] EV load profile and IESO's reported peak hours for Ontario.[12] The total EV annual kWh was then distributed across single family households using building count proportions derived from the base case load forecast. This ensured alignment with the spatial and demographic characteristics of Toronto Planning Region.

Similarly, the data centers summer MW forecast was used to calculate the annual kWh forecasts. ICF then allocated the resulting annual kWh to large office and warehouse building types, using the annual kWh proportions established in the base case load forecast to guide the distribution. This was done due to the absence of data center building type in ComStock.

This approach provided a sector-specific and building type–specific representation of future energy demand from data center operations.

### 2.3.3 Calibration Methodology for Reference Case and Electrification Case Load Forecasts

ICF used the scaled 2024 substation-level data in conjunction with IRRP demand forecasts to calibrate future load projections. This formed the basis for generating load forecasts from 2025 through 2050 at the substation level. The 2024 kWh values for each substation, derived from

[11] https://afdc.energy.gov/evi-x-toolbox#/evi-pro-loads

[12] https://www.ieso.ca/en/Sector-Participants/Settlements/Peak-Tracker

scaled totals of the hourly load, served as the baseline. ICF applied the annual growth rates from the IRRP summer MW forecasts to project annual kWh values for each substation through 2050.

To allocate residential and commercial annual kWh by substation, ICF excluded industrial load from the calibration process by subtracting its annual kWh from the total substation annual kWh forecasts. The team then calculated the annual percentage split between residential and commercial annual kWh for each substation and allocated the remaining substation annual kWh accordingly to industrial loads. In cases where calibration resulted in negative growth for residential or commercial sectors, ICF manually adjusted those values to reflect 0% growth, ensuring a realistic and stable forecast trajectory.

For both the reference and electrification cases, ICF converted each sector's annual kWh forecast at the substation level to peak MW by multiplying the annual kWh by the respective kW/kWh ratios.

### 2.3.4 End-Use Split

ICF began by determining the end-use load for the base year using digital twin simulations that enabled the team to disaggregate the total base year load by end use across each substation and building type, providing a detailed and spatially accurate energy profile.

For the 2025–2050 period, ICF projected load forecasts by end use by extrapolating energy use changes by equipment type and end use from the IESO zonal forecast and IRRP end-use forecast. These changes were applied to the base year end-use splits to generate future end-use distributions. The resulting end-use allocations were calibrated to ensure they summed precisely to the annual load forecast totals, maintaining consistency across the forecast horizon.

## 2.4 Measure List Development and Measure Characterization

To support province-wide energy planning through digital twin simulations, a detailed and sector-specific measure development process was undertaken for Ontario's residential, commercial, and industrial sectors. The goal was to prepare simulation-ready eDSM measures that reflect local building characteristics, climatic conditions, and RET opportunities. The methodology involved consolidating multiple datasets, conducting targeted gap analyses, refining measures for simulation, and estimating energy savings based on regionally adjusted performance metrics. The result is a validated and structured measure set that supports high-resolution modeling, forecasting, and BCA using a digital twin framework.

### 2.4.1 Residential Sector

The residential sector approach focused on building a comprehensive, standardized, and modular measure list compatible with the DER Insight and ResStock simulation tools used for energy modeling. The process combined foundational program assumptions, historical potential data, and archetype-level simulation outputs. Emphasis was placed on including both common and emerging technologies, ensuring the measures could be realistically applied to Ontario's diverse residential building stock.

### *Development Strategy and Structure*

The following are the key steps taken by ICF to develop the measure list and characterize the measures:

- Integrated historical program data with simulation-compatible measures to ensure coverage of all applicable equipment and residential RET technologies.
- Identified and filled gaps with measures related to envelope upgrades, efficient HVAC options, and low-income RETs.
- Standardized measures with consistent naming, applicable climate zones,[13] fuel types, and building categories in the modeling, forecasting, and BCA analysis.
- Included savings values in annual energy (kWh) and peak demand (kW) along with measure lifetime and persistence assumptions.

### *ResStock Simulation Process to Develop Measures*

ResStock simulation was used to provide granular and up-to-date measure characteristics for many of the residential sector measures. This provided savings that mimic the residential sector make-up at a dwelling level. Where database information was unavailable, measures were developed using program data from IESO and other jurisdictions. All measure characteristics were adapted to the locality as necessary:

- **Automated Workflow.** Applied directly using upgrade logic within existing ResStock simulation tools used for this study.
- **Manual Workflow.** Used for measures not natively supported by simulation tools, by editing input files manually.
- **Load Shape Application.** Applied to buildings using predefined hourly savings patterns where simulation was infeasible.

### *Measure Characterization*

- Through automated and manual workflows, a finalized list of 51 residential measures was developed (45 EE and 6 DR/DER).
- The measures developed had the following end-use categories as applicable: appliances, water heating, cooling, heating, lighting, and miscellaneous.

**Table 4** outlines all the sources that were used for residential measure characterization. As is standard practice in achievable potential studies, ICF leveraged eDSM program technical

[13] Measure savings were adjusted if savings algorithms or deemed savings were from climate regions other than the Toronto Planning Region. For example, savings estimates from Illinois were adjusted to make them appropriate for Toronto Planning region by considering the differences in heating or cooling degree days.

reference manuals (TRMs) from other jurisdictions with a similar climate to Ontario, such as Wisconsin, Iowa, and New York to address data gaps for measure characterization data.

*Table 4. Data Sources for Residential Measure Development*

| # | Parameters | Sources |
|---|---|---|
| 1 | Incremental Cost | • IESO Measure and Assumption List (provided by IESO)<br>• 2025 Illinois Statewide TRM Version 13.0, Volume 2<br>• Wisconsin Focus on Energy 2024 TRM<br>• Iowa Energy Efficiency Statewide TRM, Version 8.0<br>• New York TRM, Version 12 |
| 2 | Savings | • IESO Measure and Assumption List (provided by client)<br>• ResStock Simulations |
| 3 | Load Shapes | • EE (Existing Measures): IESO<br>• EE (Existing Measures): ResStock Simulations<br>• EE (NC Measures): 2020 National Building Code of Canada (NBC), 2024 Ontario Building Code, Toronto Green Standard, EnergyPlus Simulations<br>• DR: ICF Expertise<br>• DER: PVWatts Calculator<br>• IESO: Peak Tracker<br>• Toronto IRRP Forecasting Methodology (for EV)<br>• ResStock Simulations |
| 4 | Incentives | • Save on Energy: For Your Home<br>• ESource DSM Database of North American eDSM Programs<br>• NRCAN: Directory of Energy Efficiency Programs<br>• Dominion Energy Water Energy Rewards<br>• Eversource—Ford EV |
| 5 | Measure Life | • IESO Measure and Assumption List (provided by client)<br>• 2025 Illinois Statewide TRM, Version 13.0, Volume 2<br>• Wisconsin Focus on Energy 2024 TRM<br>• Iowa Energy Efficiency Statewide TRM, Version 8.0 |

### 2.4.2 Commercial Sector

The commercial sector required a more detailed segmentation to capture the diversity in building use, system types, and operational patterns. The development process structured the measure list to reflect these differences by organizing them according to building subsectors and end uses. Inputs were drawn from program data, ComStock building simulation databases, and sector-specific energy studies, adapted for IESO's context.

### *Development Strategy and Structure*

- Merged existing energy measures with DER Insight simulation-ready formats in existing tools to address both equipment replacement and system-based upgrades.
- Performed a gap analysis to include missing technologies such as variable-speed drives, certain controls upgrades, and operational efficiency improvements.
- Adjusted deemed savings estimates to match local weather and local system sizing assumptions.
- Normalized energy savings per square foot as applicable to allow for comparative modeling across building sizes.

### *Measure Characterization*

- 112 commercial measures (105 EE and 7 DR/DER) across 14 building types, including large offices, medium offices, small offices, standalone retail, mall retail, primary schools, secondary schools, full-service restaurants, quick service restaurants, small hotels, large hotels, outpatient clinics, hospitals, and warehouses.
- End-use categories, including lighting, heating, cooling, refrigeration, water heating, ventilation, data center, appliances, and miscellaneous.

**Table 5** outlines all the sources that were used for commercial measure characterization. ICF leveraged eDSM program TRMs from other jurisdictions with a similar climate to Ontario, such as Wisconsin, Iowa, and New York, to address data gaps for measure characterization data.

*Table 5. Data Sources for Commercial Measure Development*

| # | Parameters | Sources |
|---|---|---|
| 1. | Incremental Cost | • IESO Measure and Assumption List<br>• 2025 Illinois Statewide TRM, Version 13.0, Volume 2<br>• Wisconsin Focus on Energy 2024 TRM<br>• Iowa Energy Efficiency Statewide TRM, Version 8.0 |
| 2. | Savings | • IESO Measure and Assumption List<br>• 2025 Illinois Statewide TRM, Version 13.0, Volume 2<br>• Wisconsin Focus on Energy 2024 TRM<br>• Iowa Energy Efficiency Statewide TRM, Version 8.0<br>• 2024 Michigan Energy Measures Database |
| 3. | Load shapes | • EE (Existing Measures): IESO<br>• EE (Measure Applicability): ComStock<br>• EE (NC Measures): 2020 NBC, 2024 Ontario Building Code, Toronto Green Standard, EnergyPlus Simulations<br>• DER: Client and ICF loadshape tool<br>• DR: ICF Load shape tool |
| 4. | Incentives | • Save on Energy: For Businesses and Contractors<br>• Save on Energy: Energy Efficiency for Small Business<br>• ESource DSM Database of North American eDSM Programs |

| # | Parameters | Sources |
|---|---|---|
| | | • NRCAN: Directory of Energy Efficiency Programs<br>• NREL Annual Technology Baseline 2024 Database—Solar PV Communication Costs in 2025 |
| 5. | Measure Life | • IESO Measure and Assumption List<br>• 2025 Illinois Statewide TRM, Version 13.0, Volume 2<br>• Wisconsin Focus on Energy 2024 TRM<br>• Iowa Energy Efficiency Statewide TRM, Version 8.0 |

### 2.4.3 Industrial Sector

The industrial sector posed a unique challenge due to process-specific energy use and the variability across facilities. The measure list was developed to reflect this diversity, incorporating both equipment level and facility-wide energy savings opportunities. Focus areas included motors, industrial controls, process loads, and lighting while accounting for cross-cutting technologies.

#### *Development Strategy and Structure*

- Integrated known technology types with regionally relevant performance and cost data to create a practical list of industrial energy-saving measures.
- Reviewed sector-specific process needs to define applicable baseline and efficient configurations.
- Applied separate estimation methods for facility-wide vs. equipment-level savings.
- Ensured weather-sensitive technologies were adjusted for local climatic zones to maintain regional accuracy.

#### *Measure Characterization*

- 34 industrial EE measures (29 EE and 5 DR/DER) suitable for both standalone and integrated simulations.
- End-use categories including HVAC, cooling, process heating, process load, ventilation, lighting, and motors.

**Table 6** outlines all the sources that were used for industrial measure characterization.

*Table 6. Data Sources for Industrial Measure Development*

| # | Parameters | Sources |
|---|---|---|
| 1 | Incremental Cost | • IESO Measure and Assumption List (provided by client)<br>• 2025 Illinois Statewide TRM, Version 13.0, Volume 2<br>• ICF Database |

| | | |
|---|---|---|
| 2 | Savings | • IESO Measure and Assumption List (provided by client)<br>• NRCAN: Directory of Energy Efficiency Programs<br>• ICF Database |
| 3 | Incentives | • Save on Energy: Business and Contractors website<br>• Save on Energy: Energy Efficiency in Industrial Processes<br>• ESource DSM Database of North American eDSM Programs<br>• NRCAN: Directory of Energy Efficiency Programs |
| 4 | Measure Life | • IESO Measure and Assumption List (provided by client)<br>• OEB Industrial Measure Library |

## 2.5 Potential Estimation

ICF estimated the technical, economic and achievable potential of the eDSM measures for the Toronto Planning Region the definition of which are provided in the following subsections along with the corresponding methodology for estimating the potential. A high-level view of the hierarchy of the three potentials is shown in **Figure 3**.

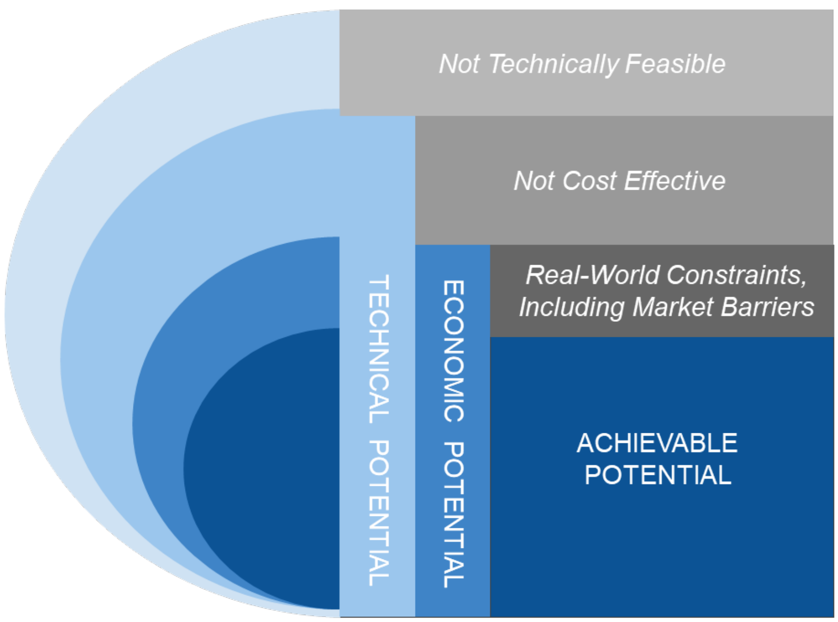


*Figure 3. Illustration of Technical, Economic, and Achievable Potential*

### 2.5.1 Technical Potential

Technical potential represents the maximum possible energy and demand savings that could be achieved if all technically feasible EE measures were implemented across the entire applicable population of end uses and buildings. The following criteria were part of ICF's estimation process for technical potential, in accordance with standard definitions:

- No financial constraints, meaning cost is not a barrier to adoption and budgets do not limit the implementation of the measures
- Full market penetration, meaning all eligible customers adopt all applicable measures immediately (see the specifics of technology type details for nuances)
- Inclusion of all currently available technologies that meet engineering performance criteria, regardless of economic viability or customer acceptance
- No interaction is assumed between measures to avoid superfluous mitigation of the impact of any measure due to maximizing the potential for another

Using the above definitions coupled with the assumptions listed for each of the technologies below, the technical potential was estimated by simulating the digital twin building models with energy-savings upgrades and using the predefined savings load shapes when the digital twins were not available. The change in equipment saturation and end-use energy intensity forecasts from the load forecasting process provided the inputs for various ROB and new construction measures to be adopted during the years of the study period. This was done at a TS level, with the resultant annual results broken down by end use and program.

***Energy Efficiency***

For EE measures, we assumed the following additional criteria apply:

- For RET measures, we assumed all eligible customers adopt all applicable measures[14] immediately, whereas for ROB and new construction, adoption occurs at equipment end-of-life or as new stock becomes available, respectively. To estimate ROB savings, a ROB-to-RET ratio is derived using the savings algorithms defined in the Illinois TRM v13. Specifically, ROB savings are calculated using federal baseline efficiency and an ENERGY STAR upgrade efficiency, while RET savings use a ResStock-derived baseline with the same upgrade efficiency.

  For example, in the case of clothes washers, the ROB baseline is 1.71 integrated modified energy factor (IMEF) compared to a RET baseline of 0.95 IMEF, with both using an upgrade efficiency of 2.07 IMEF. The resulting ROB-to-RET ratio is then applied to ResStock RET savings to scale them appropriately for ROB scenarios.

- When two or more measures are assumed to be mutually exclusive and share the market feasibility, the one with the highest demand savings is retained in the technical potential. For

[14] Note that not all measures apply to all customers. Examples in the residential sector include some homes that may not have a dehumidifier or separate freezer. In the commercial space some buildings may have commercial food service equipment or even vending machines. In industrial spaces some facilities may not have compressed air systems or even cooling. Residential measure applicability was determined using the ResStock database to estimate applicability of measures for the study area. Similarly, the ComStock database was analyzed for the commercial sector to determine applicability factors for the region. Industrial applicability was estimated using end use assessment of energy consumption from NRCAN and StatCan.

example, heat pump clothes dryer and ENERGY STAR clothes dryer in the residential sector share the market feasibility, but only heat pump clothes dryer is retained in technical potential because of higher demand savings compared to the latter.

#### *Demand Response*

For DR programs, while a traditional definition of technical potential does not produce a portfolio-level maximum possible demand savings, it does provide an insight into the individual potential of each program on a standalone basis. It is important to remember the following caveats when viewing the results for technical potential of DR in this study:

- Mutually exclusive programs such as interruptible and battery/thermal storage programs are allowed to maximize their participation in the program. In other words, even though customers can't enroll in both types of programs at the same time, technical potential modeling assumes that each program maximizes its own participation without being constrained by the other.
- The total technical potential of all programs considered can exceed the baseline load, since no interactive effects are considered.

#### *Distributed Energy Resources*

For DER programs—Solar PV and Solar PV + Battery Storage—the following additional criterion was applied, as per discussion with the IESO team:

- No network hosting capacity constraints were applied to estimate the technical potential of generation

#### *Modeling Strategy for Integrated Technologies—DR and DER*

Battery storage potential is represented in two ways: as standalone battery energy storage systems (BESS) and as part of integrated solar PV and battery systems. Standalone BESS are modeled exclusively under DR programs, providing load relief. In contrast, batteries paired with solar PV systems are treated as DERs because they contribute to both energy generation and load flexibility. As such, battery potential under DERs only reflects solar PV and battery configurations, while the total potential for batteries—including standalone systems—is captured across both DER and DR analyses.

### 2.5.2 Economic Potential

Economic potential is a subset of the technical potential which filtered out the measures that pass cost-effectiveness screening, using the Program Administrator Cost (PAC) test in this study. Economic potential has the following characteristics:

- It comprises only those measures from the technical potential pool that offer higher benefits compared to their costs over their life cycle.

- When two or more measures that are mutually exclusive share the market feasibility and clear the economic cost-effectiveness criterion, the one with the highest demand savings is retained in the economic potential.

*Note that the measures currently included in the IESO's eDSM programs were, by default, assumed to be cost-effective, including various EE measures, demand response programs and behind-the-meter distributed energy resources.*

A BCA was conducted at a measure-level for this stage of the analysis using the PAC test. The benefits and costs included for this test include:

- Benefits: Avoided costs—utility savings from reduced generation and transmission loads
  - Avoided energy costs
  - Avoided generation capacity costs
  - Avoided transmission capacity costs
- Costs[15]
  - Incentives: Available utility incentives for measures installation or continuation in the program
  - Installation costs: if provided by the utility

### 2.5.3 Achievable Potential

Achievable potential is the realistically attainable potential for energy and demand savings, accounting for actual customer adoption behavior, market barriers, and programmatic efforts. For this study, the model considered maximum achievable potential by increasing the incentives of affordability programs to be equal to the measure incremental costs and setting other incentives in the higher spectrum of the range obtained from research of other similar studies and current IESO levels. Achievable potential includes the following characteristics:

- Inclusion of customer awareness, willingness, and ability to adopt measures
- Consideration of program design factors, including incentives, outreach, financing, and regulatory policy
- Application of network hosting capacity limits for DER potential

These factors are captured within achievable potential via the participation curves which reflect uptake rates and responsiveness to program variables. ICF developed participation curves as industry-standard bass diffusion curves, using expected ramp rates and steady-state maximum market share levels. Parameters for the curves were obtained from a mix of historic program participation data from IESO, research of various potential studies and program implementation data. Accordingly, the modeling framework incorporates differentiated participation curves to reflect varying levels of program support and market engagement,

[15] Program administration costs are applied to the program level in the achievable potential.

ensuring that achievable potential estimates remain grounded in realistic adoption behavior and program responsiveness.

A sample Bass diffusion curve is shown in **Figure 4.**

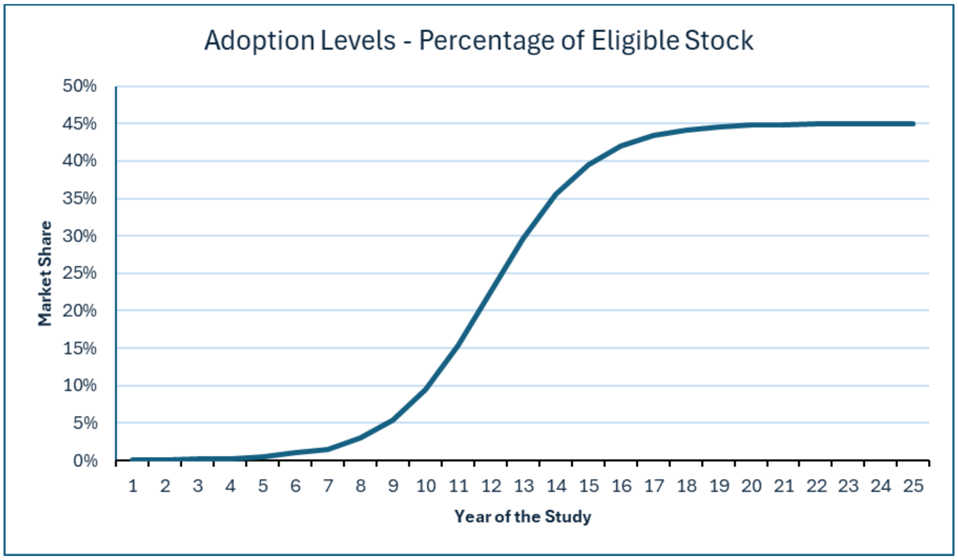


*Figure 4. Sample Bass Diffusion Curve with a Maximum Market Share of 45%*

***Energy Efficiency***

For energy efficiency measures multiple factors affect the adoption of each measure in the simulated marketplace. Factors such as distribution of efficiency levels and payback implications will affect the adoption rate of a measure.

Some measures may not be considered for adoption due to overall cost effectiveness such that a measure's overall cost is higher than the combined future benefits to the customer or society. Even measures that may be cost effective may not be adopted by the marketplace due to long paybacks periods. An example is that a residential customer may not add additional insulation because the simple payback period exceeds their expectation. Cost effectiveness was determined using avoided cost data provided by IESO and payback criteria was set by analyzing bill savings using retail rates posted on the Toronto Hydro website, and comparing to the determined costs, as discussed in the measure characterization section for each sector.

Payback period factors are also affected by the incentive amounts provided through each IESO program for each sector. Since payback measures can affect adoption rates in the Achievable potential scenario, incentives applied to measures have an effect on the adoption of these measures. Incentives were determined as discussed in the measure characterization section of each sector. Other economic factors such as inflation, changes in retail rates, and lifetime of energy efficiency measures affect the adoption of these measures in this scenario.

Many measures have multiple efficiency levels or tiers, and market adoption may be higher for lower energy efficient products due to lower initial prices.  Examples are multiple efficiency levels of heat pumps available in the market. These differences in efficiency tiers are accounted for in the analysis by analyzing the existing energy efficiency distributions in the current marketplace. For each sector measure efficiency distributions, if applicable, were determined using the information from ResStock and ComStock databases as well as other source mentioned in the measure characterization section for each sector.

The DER Insight Tool examines these factors and further calibrated the bass diffusion curves where applicable. These adoption curves were developed using technology adoption curves from NREL for factors such as maximum achievable adoption, innovation and imitation coefficients which were adjusted for the local market as needed. Changes in adoption rates and speed of adoption were adjusted to align both with available historical program data as well as published DSM plan forecast information from IESO. This ensures that achievable potential estimates are grounded in local market behavior and are reasonable.

In contrast, technical potential adoption analysis used applicability factors but also assumes that customers use the highest efficiency measures with the highest savings. Technical adoption also includes measures that are not cost-effective and assumes adoption of measures regardless of payback.

***Demand Response***

For demand response measures multiple factors affect the adoption of each measure in the simulated marketplace. Adoption rates across all programs were modeled using Bass diffusion curves. Parameters such as maximum achievable adoption and annual ramp rates were informed by studies from NREL and PNNL, supplemented by ICF's domain expertise and historical data from market studies, evaluation reports, and program plans from comparable regions.

For existing programs—such as Residential Smart Thermostats—adoption ramp rates incorporated historical participation data and projections from current program plans. For new demand response measures and offerings not currently available through IESO, ramp rates were primarily guided by ICF's implementation experience in other jurisdictions. This includes pilot programs and deployments for EV chargers, water heaters, and battery systems across North American utilities, which were used to forecast potential performance in the Toronto market.

***Distributed Energy Resources***

For solar photovoltaic (PV) systems, the calibration of Bass diffusion curves used in projecting future adoption across residential, commercial, and industrial sectors was informed by the trajectory of existing contracted distributed generation from 2025 through 2029. This approach ensures that projections are grounded in observed market behavior and reflect realistic growth patterns. In the case of battery storage systems paired with solar PV, a 10% attachment rate—outlined in Appendix C—was applied to estimate the combined potential of the Solar PV + Battery Storage measure.

The Bass diffusion curves were developed with upper bounds on market share constrained by technical feasibility: 11.98% for the residential sector and 36.20% for commercial and industrial sectors[16]. However, these bounds do not imply that market saturation will reach these levels within the study period, particularly in contrast to demand response measures. The calibration process, which incorporates historical data and growth rates derived from the IRRP forecast for contracted solar, results in more conservative and realistic adoption trajectories. These curves inherently account for market limitations such as fragmented customer awareness, competing capital investment priorities, and infrastructure constraints. While network hosting capacity limits from the IRRP forecasts were applied for each substation, those did not turn out to be binding constraints since the projected installations were lower than the limits.

It is important to highlight that the final potential estimates deliberately exclude contributions from existing distributed generation and their associated peak capacity, as the contributions of these resources are already captured in the IRRP demand forecasts and needs analysis. This approach ensures that the estimates reflect only the incremental potential beyond what has already been contracted. Furthermore, the calculation of peak savings incorporates a capacity factor of 18.4% for summer and 15% for winter, which corresponds to a higher installed capacity than what is projected for peak savings.

***Program-Level Aggregation***

The final step in generating the results for achievable potential involves aggregating the participation-applied savings and cost data to derive program-level insights:

- Annual Cumulative Achievable Potential:
  - Aggregated from individual measure-level adoption across years and substations.
- Program-Level Cost Summaries:
  - Includes program administrative costs beyond measure-level costs described in the economic potential analysis.
  - Incorporated the adoption levels of measures/programs.
- Program-Level Benefit-Cost Outputs:
  - BCA is recalculated at the program level and the benefit-cost ratios are reported.
  - This is done for all BCA tests including PAC test, Total Resource Cost test, Societal Cost Test, Ratepayer Impact Measure test, and Participant Cost Test.

[16] Appendix C provides further details on how the technical feasibility bounds were generated.

# 3 RESULTS

The outputs across all levels of potential are generated at the level of substation, sectors, and subsectors. The estimated potential for summer and winter demand, and energy savings is listed in the outputs. The potential at each level is also reported by the end uses. In this section, we discuss the cumulative outputs aggregated over the Toronto Planning Region at the technical, economic and achievable potential levels in both reference and HE scenarios.

## 3.1 Summer Demand Savings

- The overall summer demand savings potential is plotted in Figure 5.

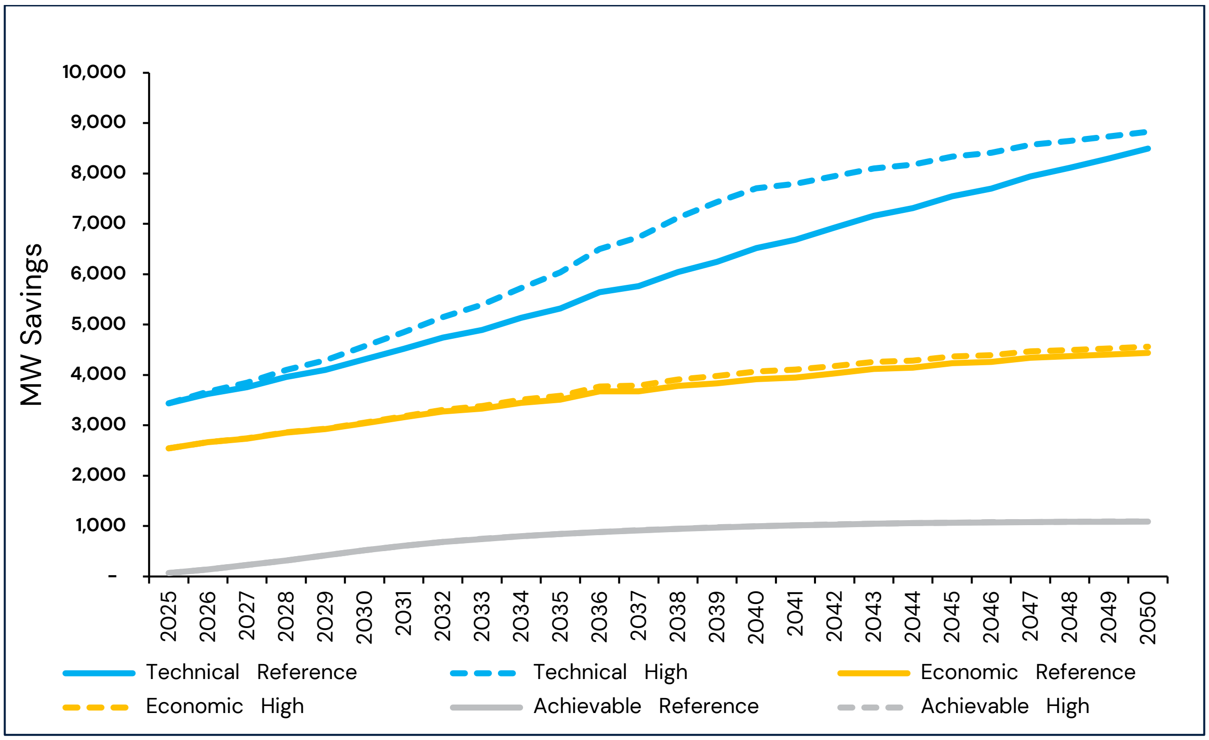


*Figure 5. Summer Demand Savings by Potential Type and Scenario*

As shown in the figure, the technical potential in the high scenario begins close to the reference scenario. The difference between these scenarios increases during the middle years and decreases toward the end of the study. The economic potential gap remains comparatively small due to the inclusion of cost-effective measures. For the achievable potential, the difference is minimal.

Figures 6, 7, and 8 below present the potential by program types: EE, DR, and DER programs. DR comprises the largest portion of technical potential, followed by DER and then EE. Because some DR measures are not cost effective, DER represents the largest portion of economic potential. The achievable potential reflects an adoption curve based on the application of real-world factors to economic potential. The overall achievable potential is about one eighth of the technical potential.

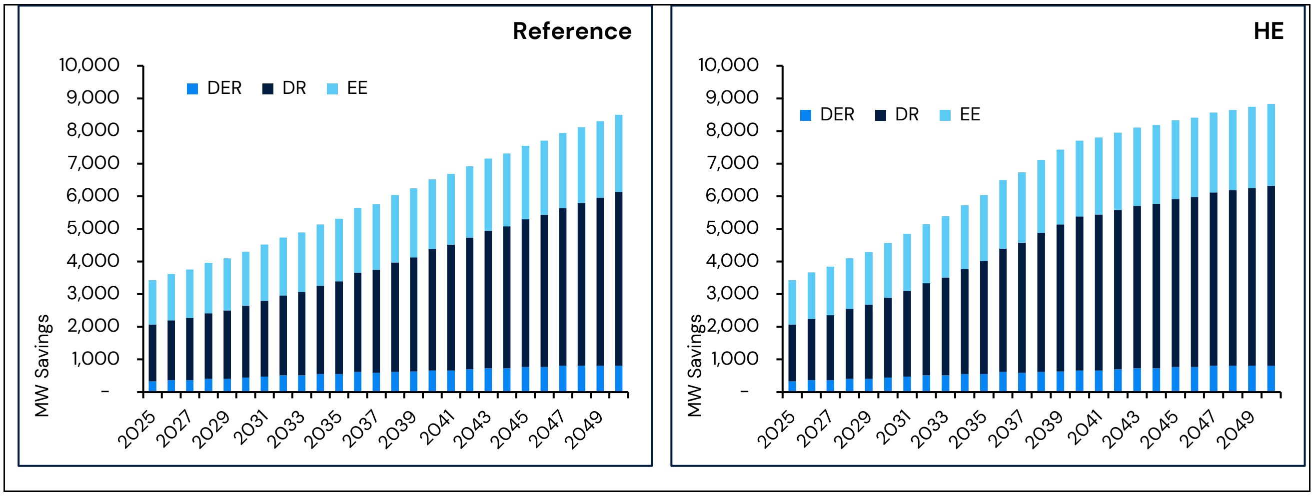


*Figure 6. Reference and HE Technical Potential Broken Out by EE, DR, DER*

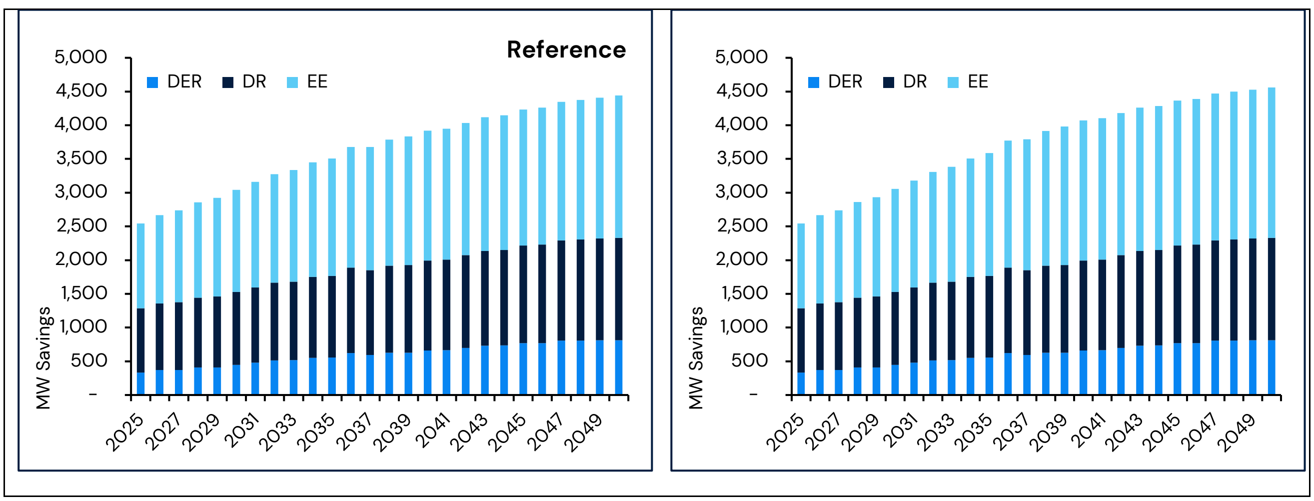


*Figure 7. Reference and HE Economic Potential Broken Out by EE, DR, DER*

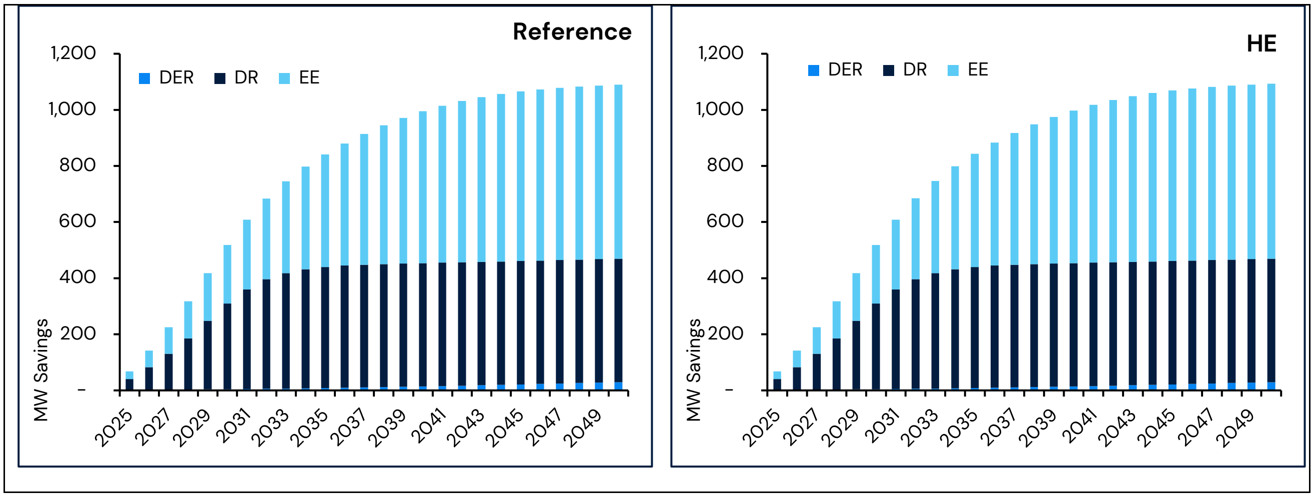


*Figure 8. Reference and HE Achievable Potential Broken Out by EE, DR, DER*

In the subsequent sections, we review the potential breakdown by EE, DER, and DR

### 3.1.1 Energy Efficiency

Figure 9 displays trends in EE potential. In both scenarios, economic potential is marginally lower than technical potential, while achievable potential remains significantly below both. Also, the difference in achievable savings potential between the reference and high scenarios is small. This is due to two main factors: 1) Anticipated electrification measures, such as heat pumps, are primarily implemented in later years while a significant number is installations for efficiency upgrades are happening in the early years due to the maturity of EE programs, 2) Toronto Green Standard sets high baseline energy performance standards for new buildings, which limits the new construction potential.

Figures 10–12 indicate that the Commercial sector accounts for the largest portion of energy efficiency potential, with the Residential sector following, and the Industrial sector contributing the least.

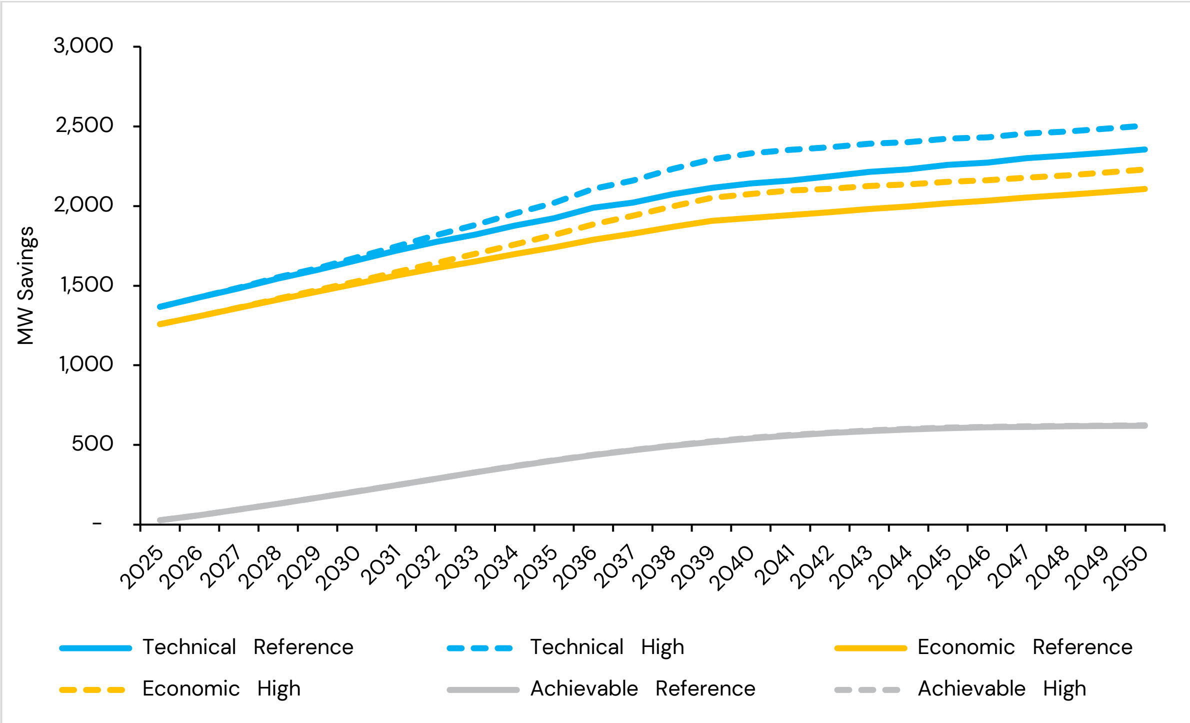


*Figure 9. EE Summer Demand Savings by Potential Type and Scenario*

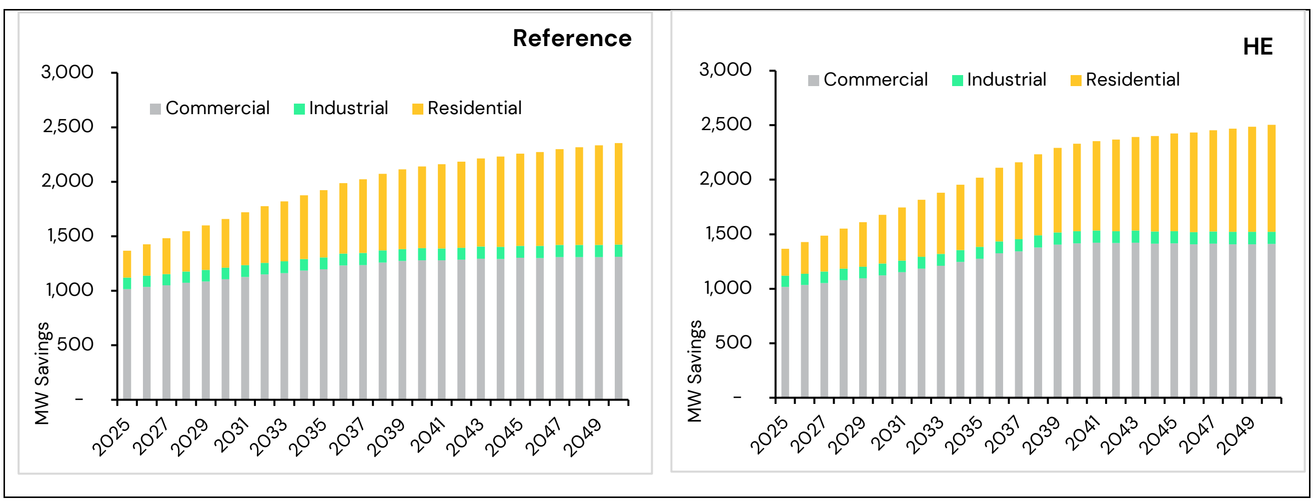


*Figure 10. EE Summer Demand Technical Potential by Sector*

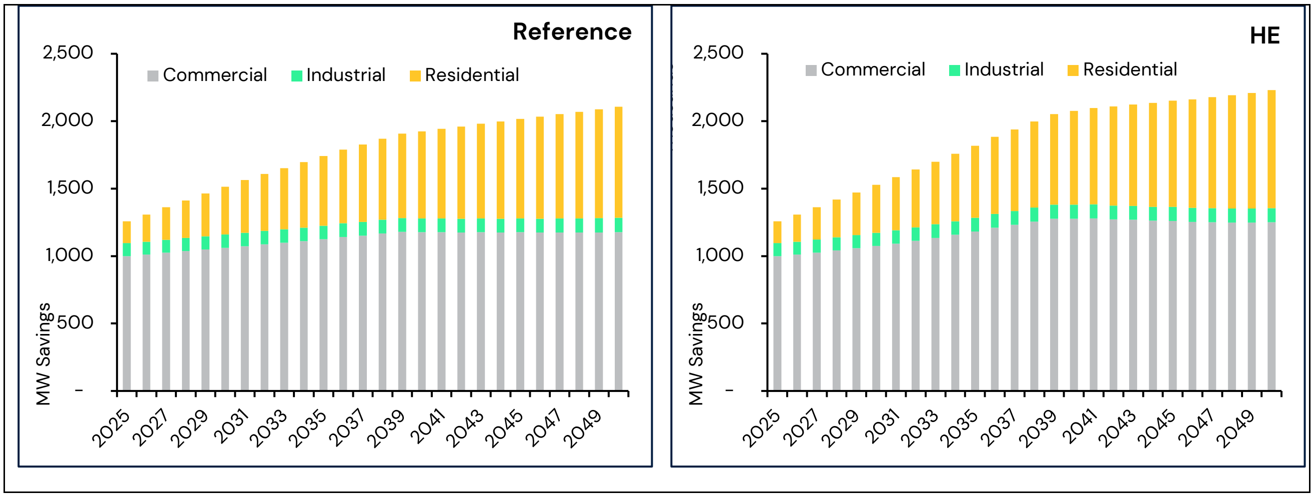


Figure 11. EE Summer Demand Economic Potential by Sector

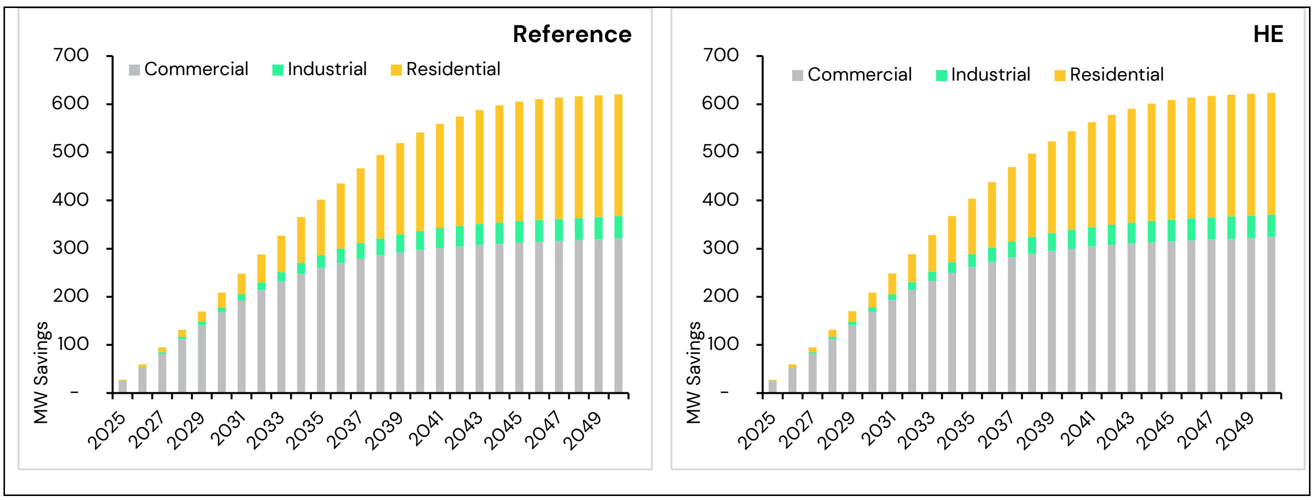


Figure 12. EE Summer Demand Achievable Potential by Sector

### 3.1.2 Demand Response

Figure 13 presents the technical, economic, and achievable potential of DR programs.

Technical potential shows a significant potential going into 2050, but it is important note that the total is a summation of individual program capability and represents a theoretical upper bound on the true potential. This is due to the fact that technical potential ignores how in practice battery/thermal storage potential and interruptible load potential would constrain each other.

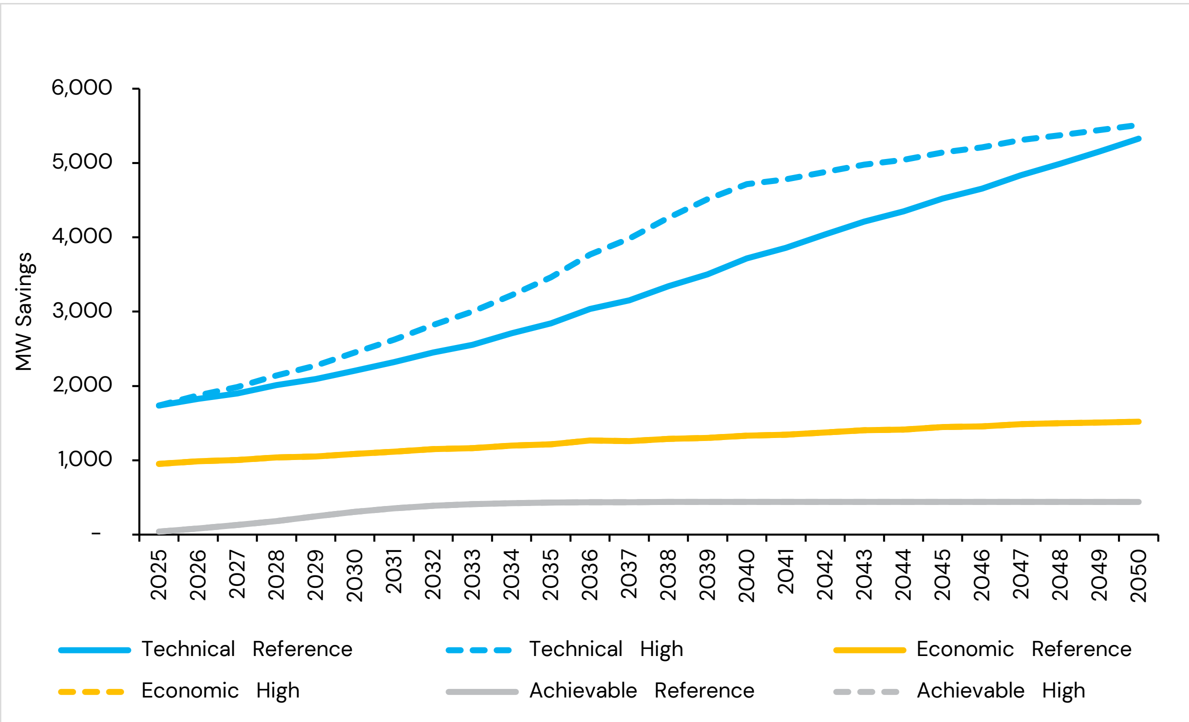


*Figure 13. DR Summer Demand Savings by Potential Type and Scenario*

The variance between the reference and high scenarios in terms of technical potential is attributed to residential EV charger demand response due to the two scenario's differing assumptions about EV adoption. It is important to note that the per vehicle potential, and as a result the program technical potential, is significantly impacted by Ontario's time-of-use-rates. The low overnight rates increase the tendency for overnight charging instead of plugging in early evenings (which coincide with the peak hours) and that usage shift mitigates the peak savings potential. As for the other potentials - the EV Chargers program is not cost-effective and consequently it does not influence the economic or achievable potential.

Also, as mentioned in the methodology section of this report, standalone battery energy storage solution (BESS) is captured as part of DR and not BTM DER. So, the total DR potential also includes behind-the-meter storage potential in its technical potential. However, BESS is not cost-effective and hence doesn't show up in economic or achievable potential.

All other programs have the same influencing factors, such as the number of smart thermostats[17], between the two scenarios, resulting in identical economic and achievable potential across both cases.

Figures 14–16 illustrate demand response potential by sector. The residential sector consistently leads, followed by commercial and industrial sectors.

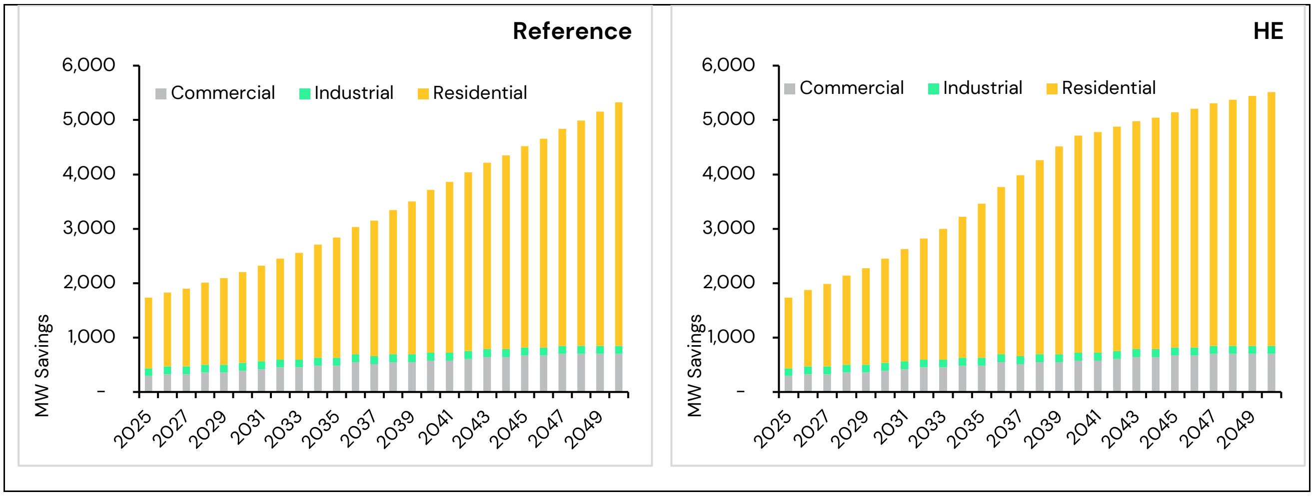


*Figure 14. DR Summer Demand Technical Potential by Sector*

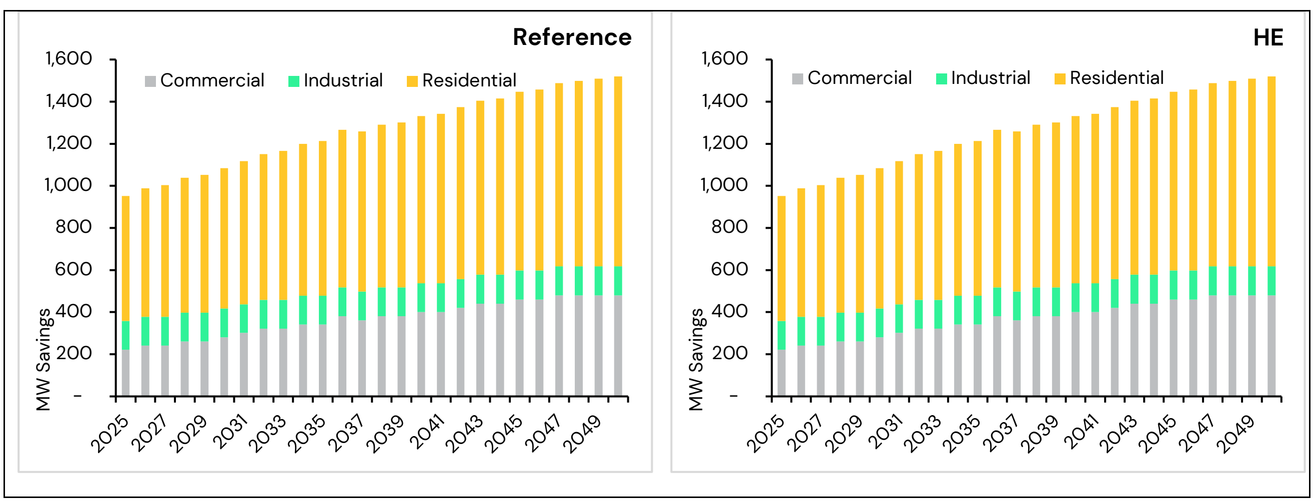


*Figure 15. DR Summer Demand Economic Potential by Sector*

[17] Note that this was an assumption considering that forecasted summer demand growth generally creates needs earlier than winter and hence the installation of DR-enabling equipment is guided by the summer programs. Electrified heating, thus, does not show an impact resulting in identical reference and HE case results.

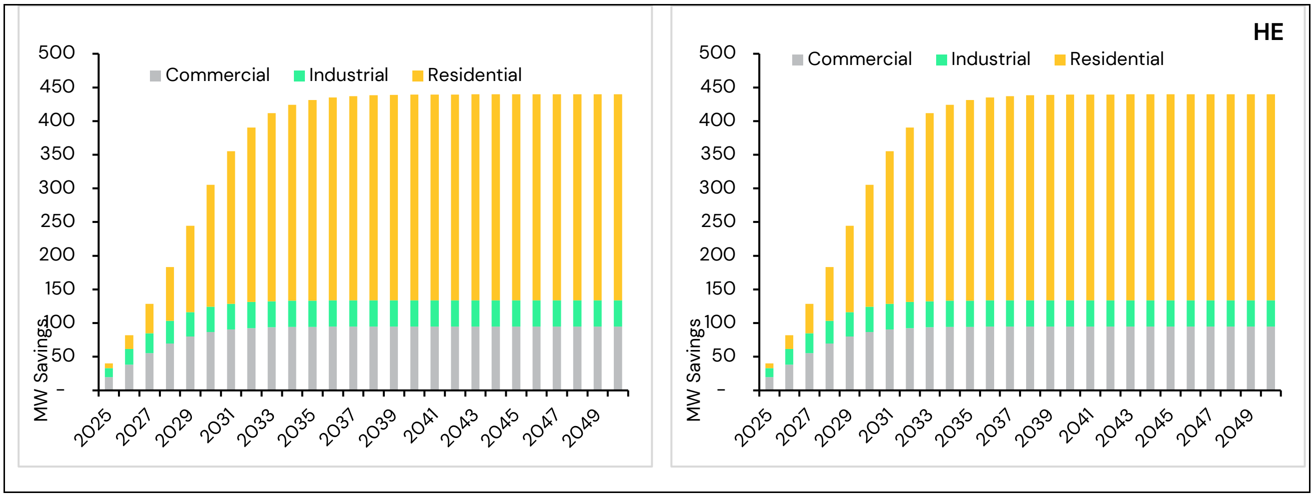


*Figure 16. DR Summer Demand Achievable Potential by Sector*

### 3.1.3 Behind-the-Meter Distributed Energy Resources

Figure 17 shows the BTM DER potential. Since Solar PV and solar PV+Storage are unaffected by electrification scenarios, their potential remains unchanged across both scenarios. With all the DER measures included post cost effectiveness, the economic and technical potentials are equal; however, achievable potential is much lower since we are reporting installations that are incremental to the capacity from existing contracts[18], and due to the factors including in the development of adoption curves (as discussed in Section 2.5.3). Figures 18–20 display these potentials by sector, with the commercial sector having the highest values.

[18] The existing installations form a significant share of achievable potential but given that they are still small numbers compared to technical and economic potential, their impact is not felt significantly for those potentials.

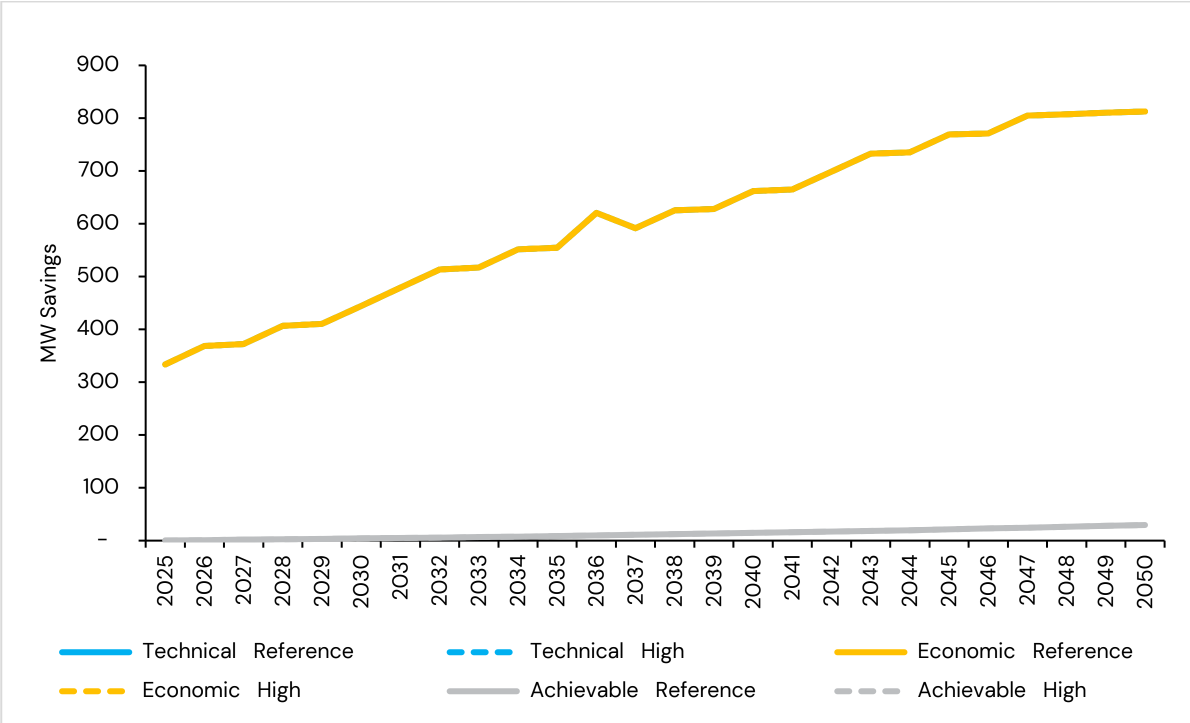


*Figure 17. BTM DER Summer Demand Savings by Potential Type and Scenario*

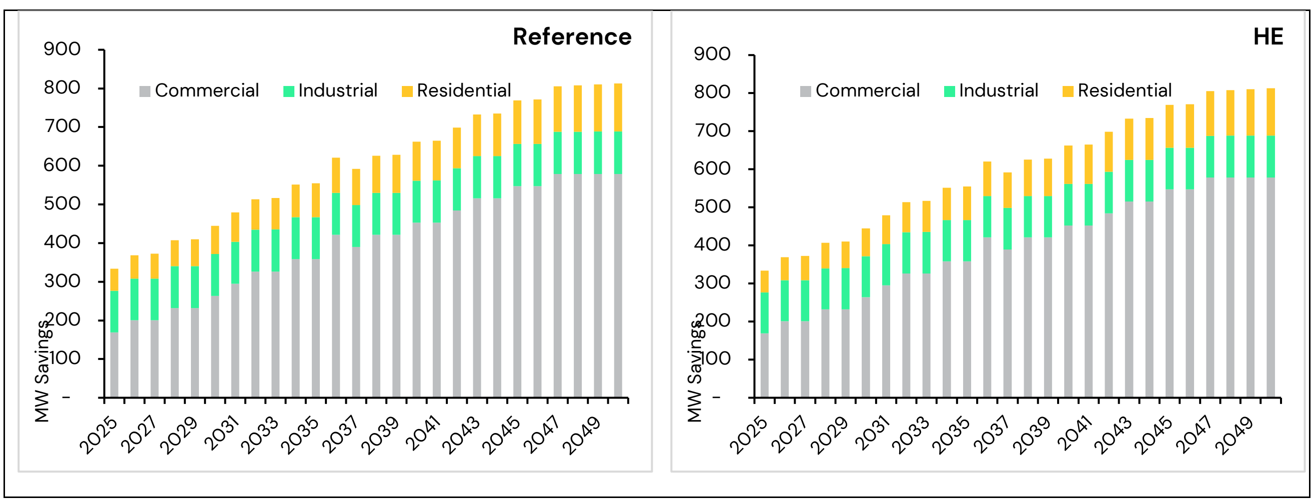


*Figure 18. BTM DER Summer Demand Technical Potential by Sector*

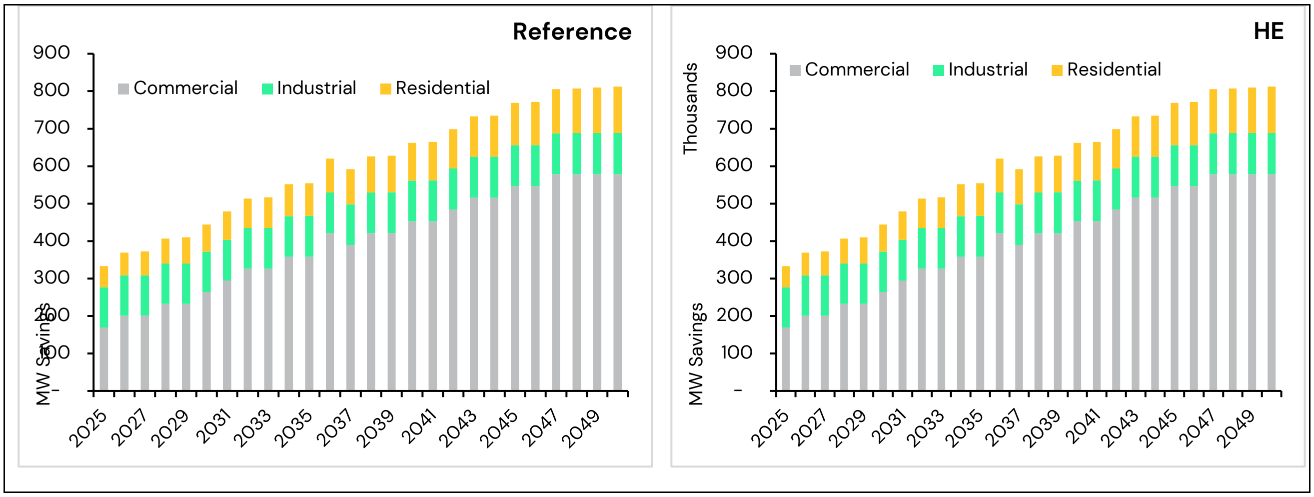


*Figure 19. BTM DER Summer Demand Economic Potential by Sector*

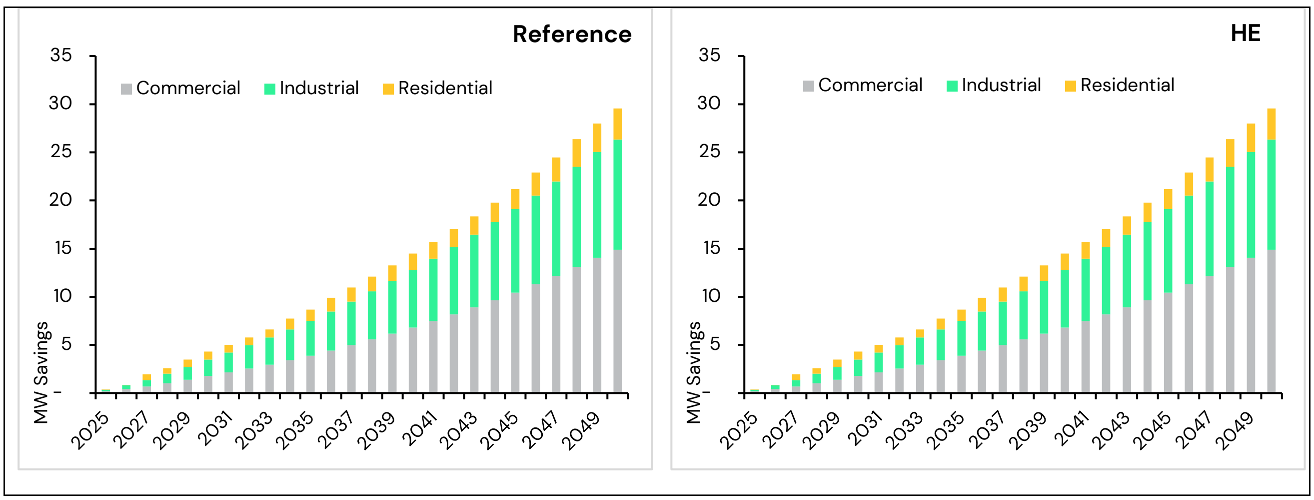


*Figure 20. BTM DER Summer Demand Achievable Potential by Sector*

## 3.2 Winter Demand Savings

Figure 21 displays winter demand savings by scenario, reflecting a trend similar to that of summer demand savings potential. The gap between the reference and high scenarios in terms of technical and economic potential is comparatively larger. This difference arises from the increased savings associated with greater heat pump adoption resulting from projected electrification.

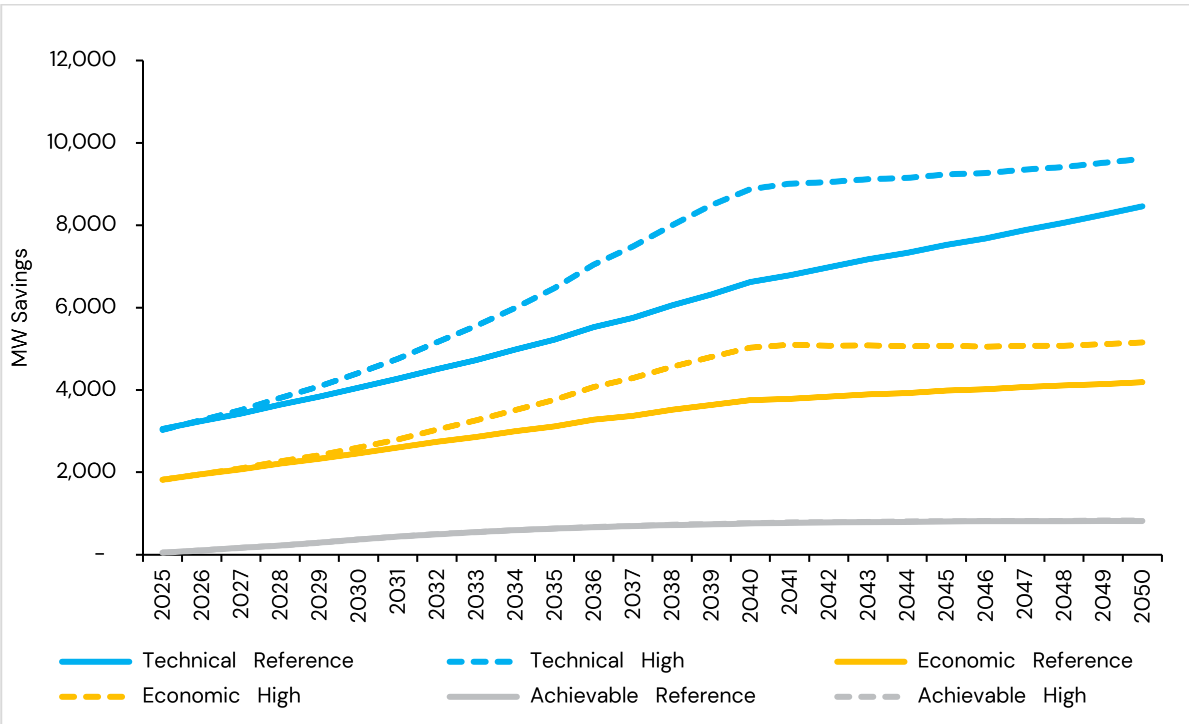


*Figure 21. Winter Demand Savings by Potential Type and Scenario*

Figures 22–24 display winter demand savings for technical, economic, and achievable potential under reference and high scenarios. Most potential comes from the residential sector, then commercial and industrial.

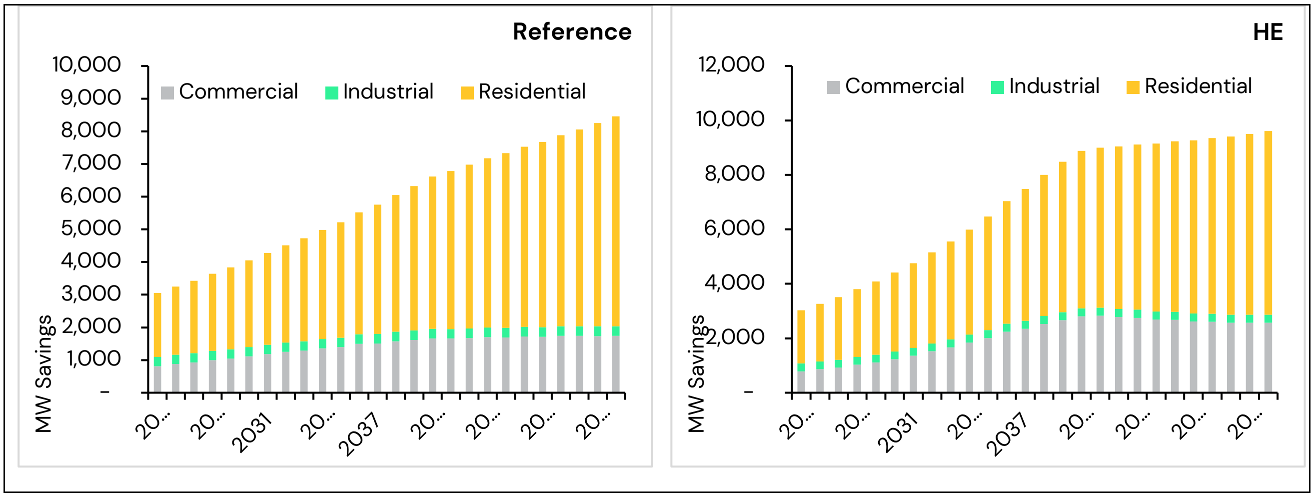


*Figure 22. Reference and HE Technical Potential Broken Out by EE, DR, DER*

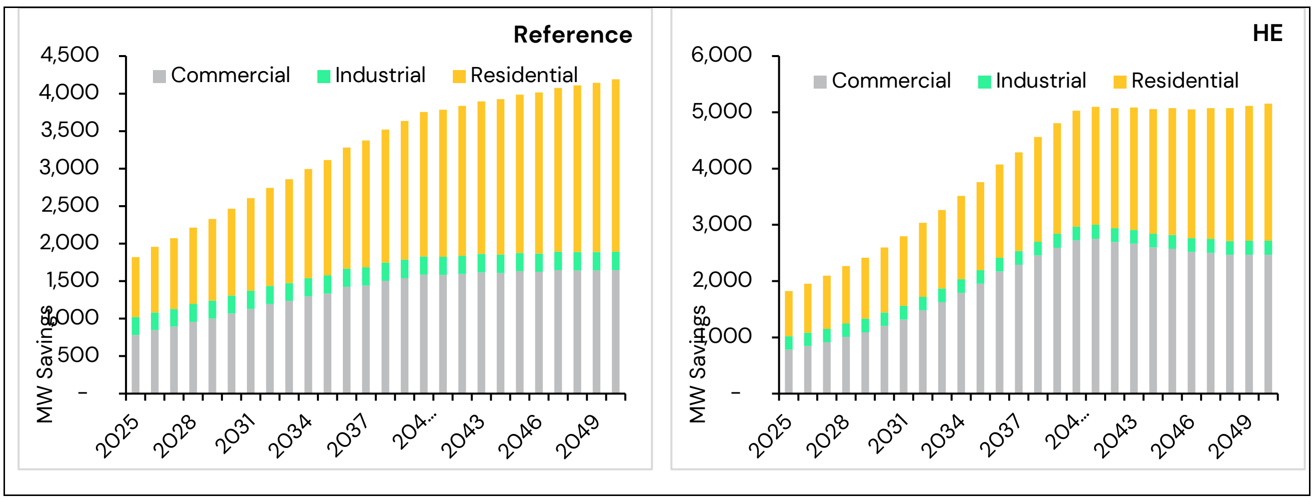


*Figure 23. Reference and HE Economic Potential Broken Out by EE, DR, DER*

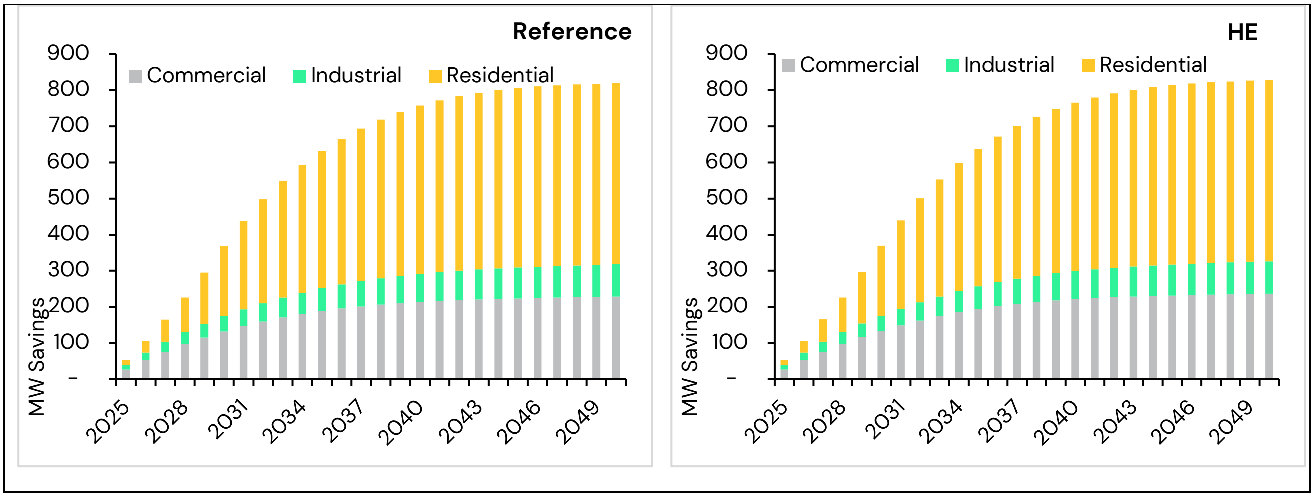


*Figure 24. Reference and HE Achievable Potential Broken Out by EE, DR, DER*

The following sections examine the potential by program types: EE, DR, and DER programs.

### 3.2.1 Energy Efficiency

The technical and economic potential for winter demand savings from energy efficiency measures is greater in the high electrification scenario, primarily due to the increased adoption of heat pumps. Note that electrification is assumed to add baseline efficiency heat pumps consequently increasing the eligible stock for energy efficiency measures. So, for technical and economic potential, the additional stock is available to upgrade as and when electrification happens. This is in contrast to what happens with achievable potential wherein heavy adoption of heat pumps is happening in the early years (as per the adoption curve, details of the methodology in Section 2.5.3) when electrification is just starting to show up and is reaching saturation levels leaving less room for upgrades when electrification picks up pace. Hence, the difference in achievable potential between the reference and high electrification scenarios is less pronounced compared to technical and economic potentials. Additionally, similar to summer demand potential, new construction potential is limited by the high baseline efficiency levels set by Toronto Green Standard.

Figures 26-28 illustrate the distribution of energy efficiency potential by sector over time, corresponding to technical, economic, and achievable potentials, respectively.

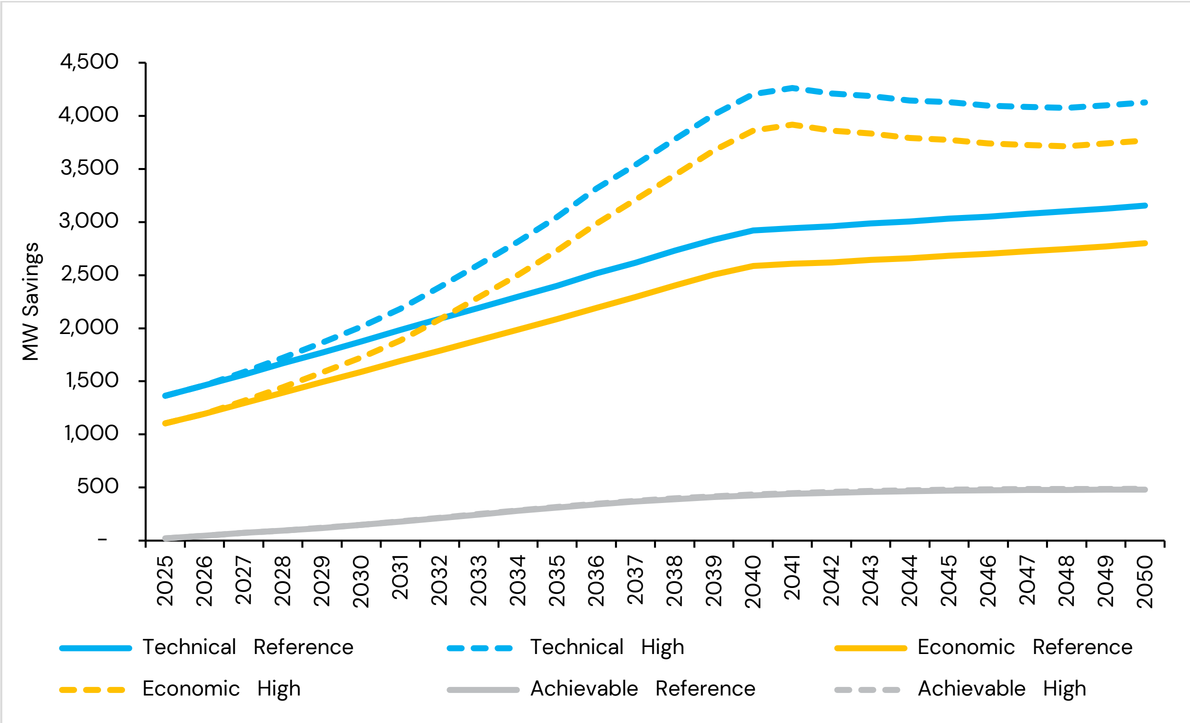


*Figure 25. EE Winter Demand Savings by Potential Type and Scenario*

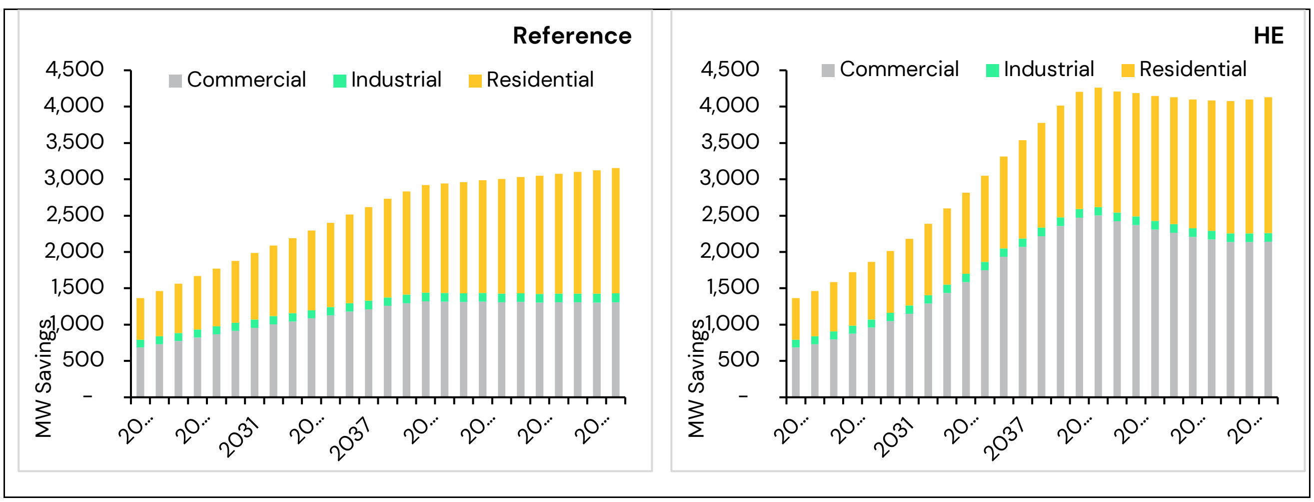


*Figure 26. EE Winter Demand Technical Potential by Sector*

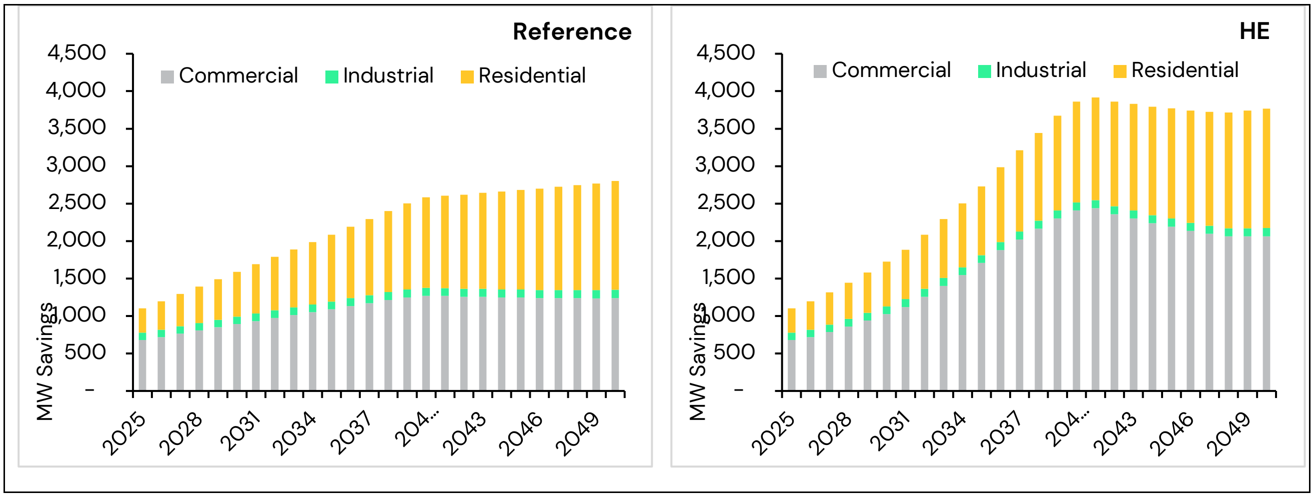


*Figure 27. EE Winter Demand Economic Potential by Sector*

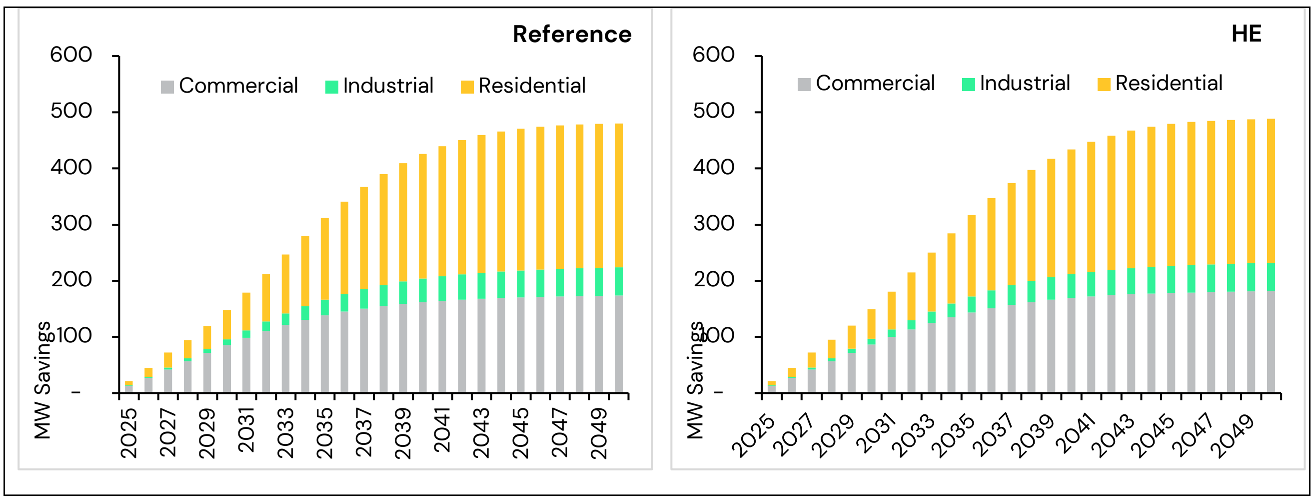


*Figure 28. EE Winter Demand Achievable Potential by Sector*

### 3.2.2 Demand Response

Figure 29 shows the technical, economic, and achievable winter DR potential. Note that the reporting is consistent with summer demand savings, with standalone BESS being captured as part of DR for winter. Similarly, technical potential for winter also serves as a theoretical upper bound given how technical potential ignores how, in practice, battery/thermal storage potential and interruptible load potential would constrain each other

Also, as in the case of summer demand, only the technical potential varies in winter demand; economic and achievable potential remain constant across both reference and high electrification scenarios. The difference in technical potential between reference and high electrification scenarios is driven by the EV demand response program which is a function of EV sales projection in both scenarios.

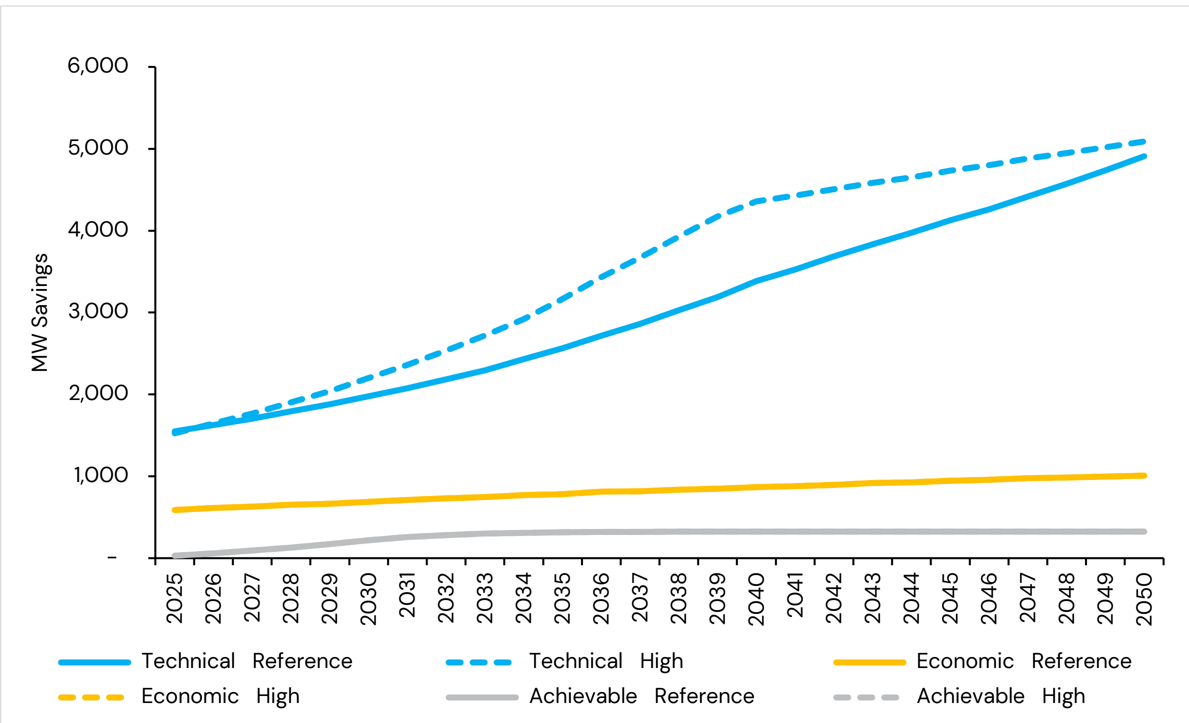


*Figure 29. DR Winter Demand Savings by Potential Type and Scenario*

Figures 30–32 illustrate winter demand response potential by sector. Residential potential significantly exceeds commercial, mainly due to the higher coincidence of residential peak hours with system peak hours, and the fact that these hours are outside of 'operational hours' for many commercial facilities.

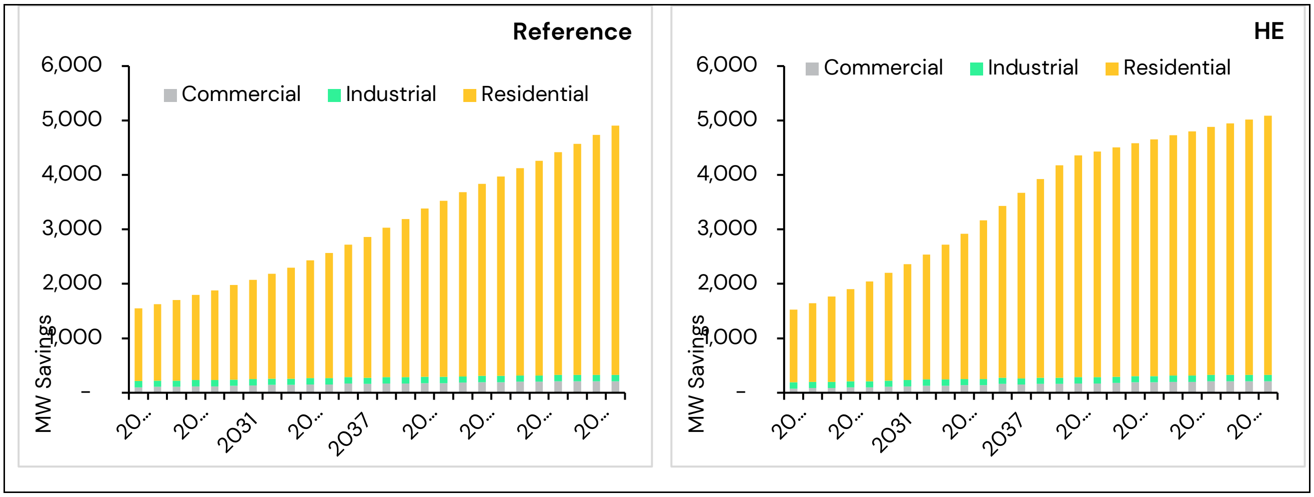


*Figure 30. DR Winter Demand Technical Potential by Sector*

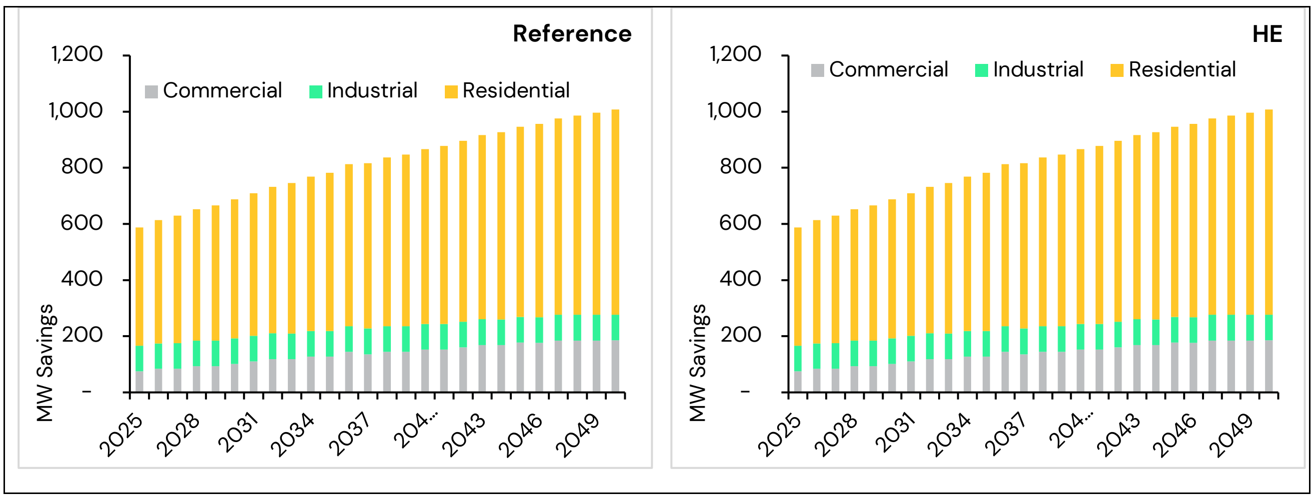


*Figure 31. DR Winter Demand Economic Potential by Sector*

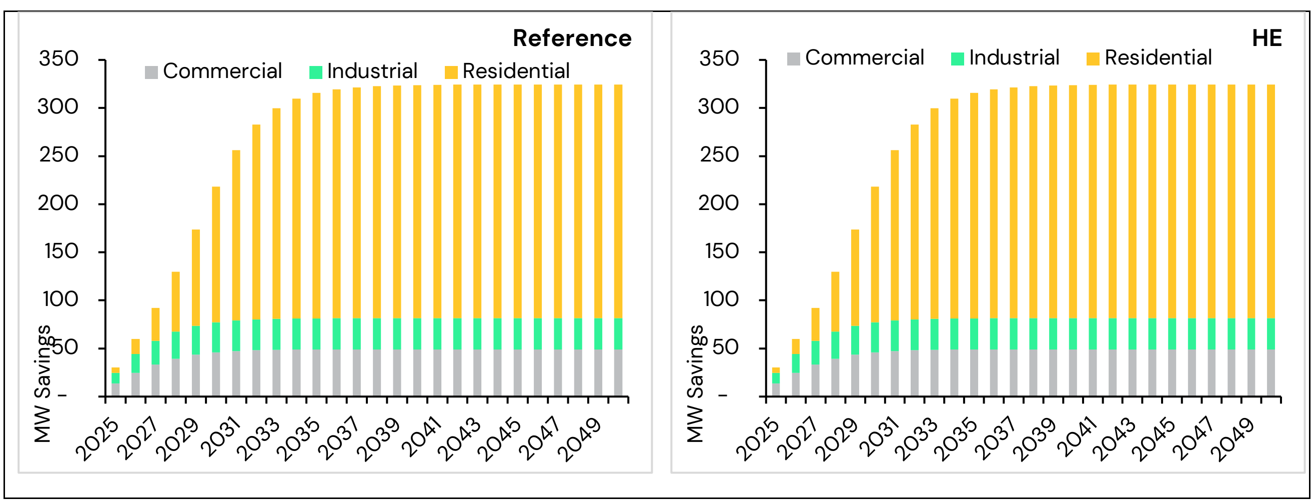


*Figure 32. DR Winter Demand Achievable Potential by Sector*

### 3.2.3 Behind-the-Meter Distributed Energy Resources

Figure 33 illustrates the BTM DER potential. Since BTM DER measures are unaffected by the electrification scenario, both scenarios yield identical potential values. With all the DER measures included post cost effectiveness tests, the economic potential matches the technical potential. However, the achievable potential is notably lower than both technical and economic estimates since we are reporting installations that are incremental to the capacity from existing contracts[19], and due to the factors including in the development of adoption curves (as discussed in Section 2.5.3).

Figures 34, 35, and 36 present the breakdown of technical, economic, and achievable potential by sector, revealing that the commercial sector contributes the most significant portion.

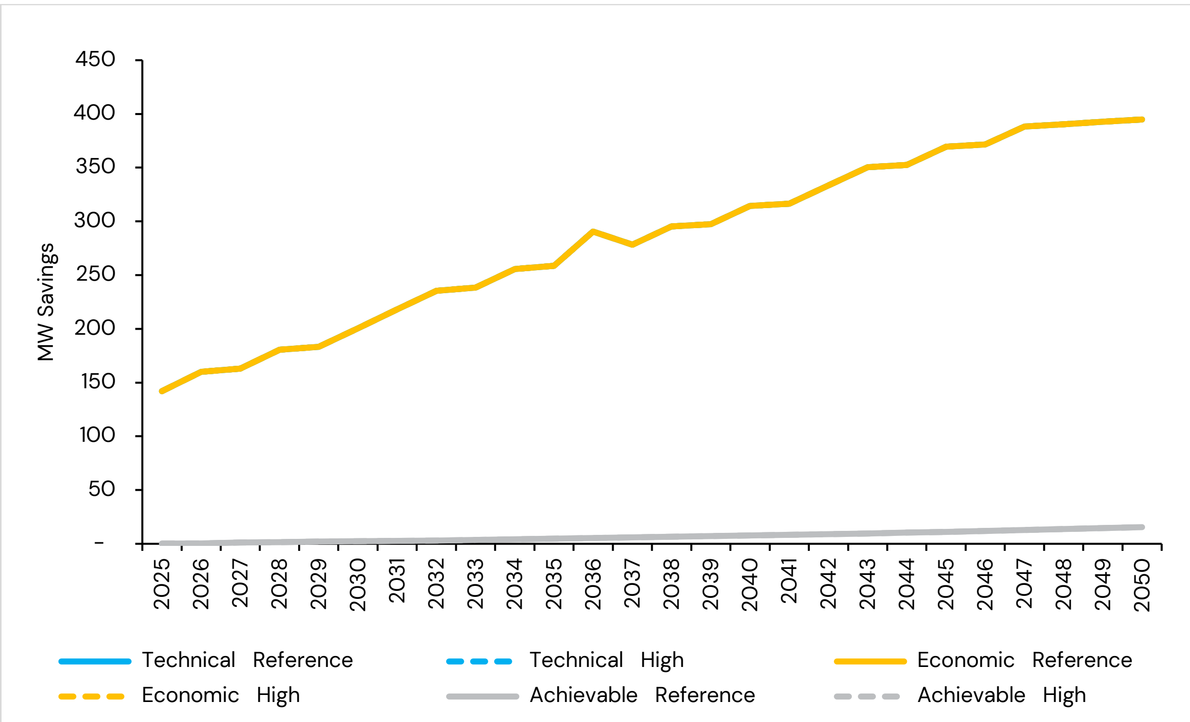


*Figure 33. BTM DER Winter Demand Savings by Potential Type and Scenario*

[19] The existing installations form a significant share of achievable potential but given that they are still small numbers compared to technical and economic potential, their impact is not felt significantly for those potentials.

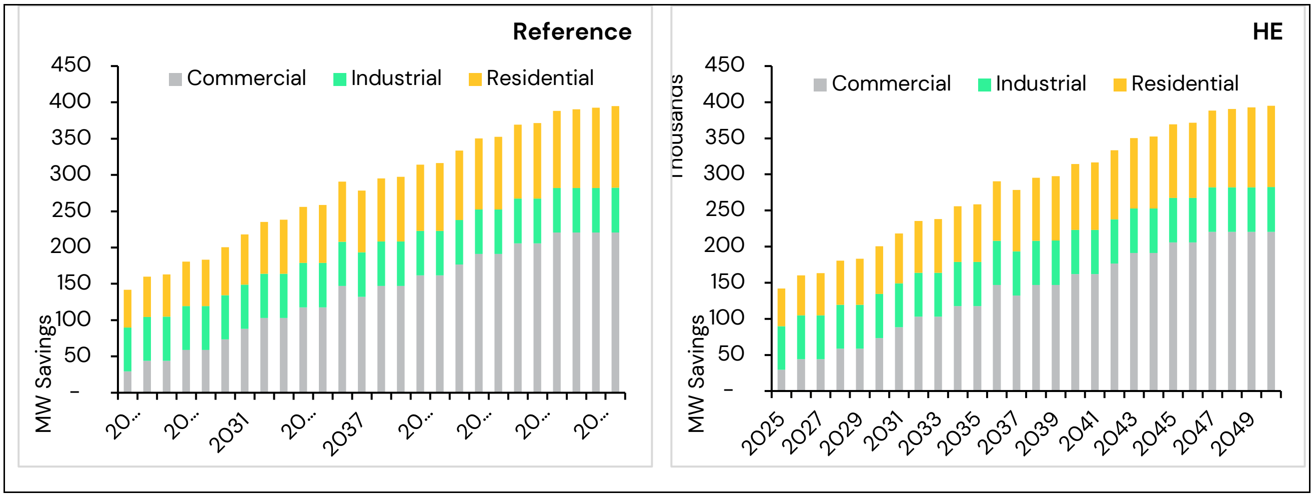


*Figure 34. BTM DER Winter Demand Technical Potential by Sector*

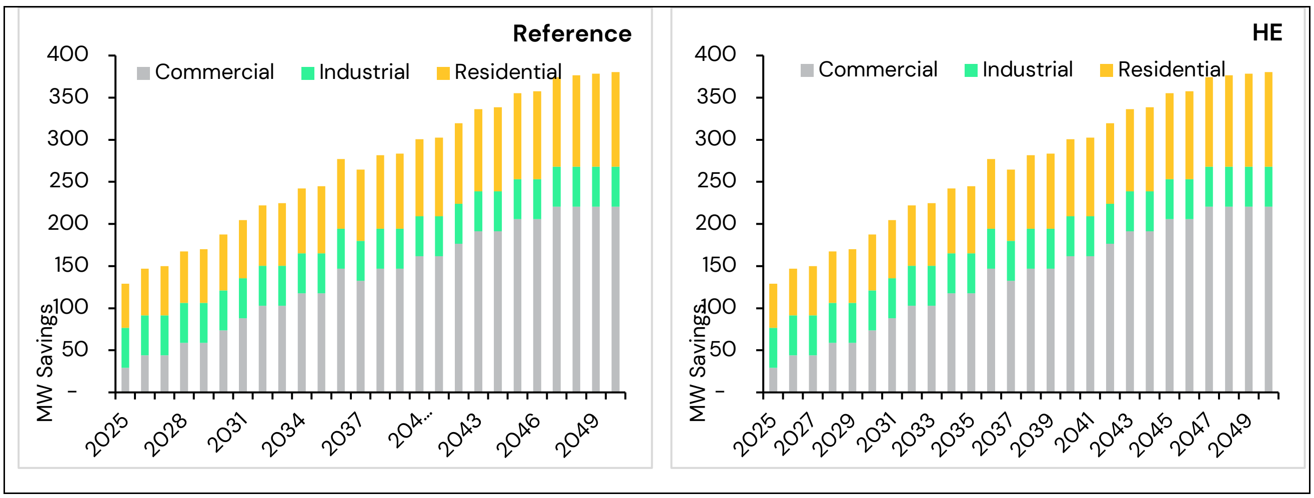


*Figure 35. BTM DER Winter Demand Economic Potential by Sector*

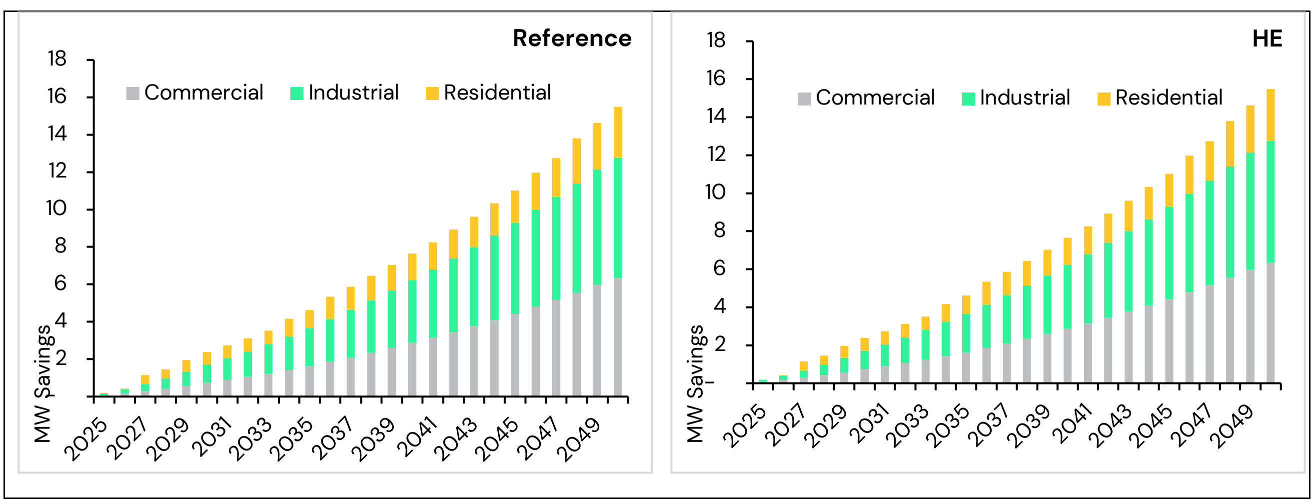


*Figure 36. BTM DER Winter Demand Achievable Potential by Sector*

# APPENDICES

## A. Measure Characterization

Embedded files in this section provide the complete measure characterization for all sectors.

Residential Measure Characteriz

Commercial Measure Characteriz

Industrial Measure Characterization - IE

## B. Additional Assumptions and Inputs

The additional inputs file provides information on

- Non-measure inputs
- DR maximum market shares
- DER nameplate capacities[20]

Additional Modeling Inputs - IE

## C. DER Methodology

To assess the maximum market saturation of DERs in Toronto's residential and C&I sectors, the following structured approach was employed:

The SolarTO Map[21] data served as the foundational resource for evaluating solar potential across the city. Using this dataset, the residential and C&I sectors were segmented based on estimated system sizes: Systems under 11 kW were categorized as residential, while those 11 kW and above were classified as C&I. This segmentation yielded an initial estimate of available roof areas to deploy solar there by determining the technical potential of 27.2% for the residential sector and 45.03% for the C&I sector.

To refine these estimates, ICF excluded PV systems below 5 kWdc in the residential sector, deeming them too small to be viable. This exclusion targeted systems on roofs with complicated geometries, which the SolarTO Map identified as potentially suitable for solar installations, though with capacities on the order of 0.02 kWdc. Additionally, systems in the

[20] The sizes for solar PV and battery storage were determined from the combination of (1) system size determination from historical DER data, (2) ICF expertise on typical average system sizes

[21] https://www.toronto.ca/services-payments/water-environment/net-zero-homes-buildings/solar-to/solarto-map/

range of 3 kWdc to less than 5 kWdc were excluded, as installations of such small sizes are uncommon in Toronto's residential sector.

This approach aligns with established practices in solar potential assessments for Ontario, including Toronto. Industry reports and guidelines indicate that residential solar PV systems typically have a baseline capacity of approximately 5 kW, reflecting economic and practical considerations for viability. Very small systems, such as those below 3 kWdc or in the 0.02 kWdc range, are not representative of common installations due to limited energy output, higher relative costs per kW. With that said, SolarTO Map, developed by the City of Toronto, provides broad estimates of rooftop potential but often requires such refinements to account for real-world feasibility, including roof complexity and minimum viable sizes.

Further adjustments were made to account for existing installed systems, structurally sound buildings suitable for solar installation, and terminal substations that were constrained. These adjustments resulted in a revised maximum technical potential of 11.98% for residential and 36.20% for C&I.

Finally, a 10% attachment rate was assumed for PV systems paired with BESS across both sectors. These BESS attachment rates were primarily informed by rates observed in the United States—specifically, approximately 12% for residential systems and 8% for nonresidential systems, as detailed in the Lawrence Berkeley National Laboratory Tracking the Sun Report—due to the absence of adequate data for Canadian markets.

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