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# Hamilton Area Addendum

Forecast Methodology Document  
JUN 29, 2026

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# Demand Forecast Methodology

The demand forecast methodology follows the following steps, which are detailed in this document.

1. Forecast Starting Point Creation
2. Scope of Demand Forecast Scenarios
3. Median-Weather Gross Demand Forecasts
4. Forecasted Distributed Generation
5. Electricity Demand Side Management Assumptions
6. Forecasted Extreme Temperature
7. Final Peak Forecast by Station

## 1. Forecast Starting Point Creation

The forecast starting point is the historical demand for a representative reference year (2026 for the Hamilton Area Addendum) on which Local Distribution Companies (LDCs) build their gross demand forecasts.<sup>1</sup>

To produce the forecast starting point for LDCs, the IESO must first unbundle existing distributed generation (DG) impacts from measured historical net demand, to produce historical gross demand, and then weather-normalize the historical gross demand. To produce historical gross demand, the historical hourly output of existing DG facilities<sup>2</sup> is added back onto the measured historical net demand of stations. The weather-normalization methodology is discussed in the following subsection

1.1. For more information on producing the forecast starting point, please see Section 6.1 of the [Load Forecast Guideline](#) for regional planning, published by the Ontario Energy Board through the [Regional Planning Process Advisory Group](#).

The Technical Working Group (TWG) used non-coincident peak demands for the starting points and for the gross forecasts produced by the LDCs.

The TWG used either the 2025 weather-normalized demand or the average of the 2021-2025 weather-normalized demand as the starting point of the forecast. The choice was made depending on whether station loading had been growing over the 5-year historical period (indicating the last year is most representative), or if the loading had been approximately constant.

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<sup>1</sup> A gross forecast means that existing and new distributed generation, and new electricity demand side management savings are not accounted for in the forecast. Once distributed generation and electricity demand side management savings are accounted for, they will reduce the gross forecast to produce a net demand forecast: the forecasted demand to be experienced by electricity system infrastructure.

<sup>2</sup> When available, the measured hourly output of DG facilities is used; but if unavailable, the hourly output is estimated using the measured hourly capacity factors of aggregated facilities and the installed capacity of the facilities.

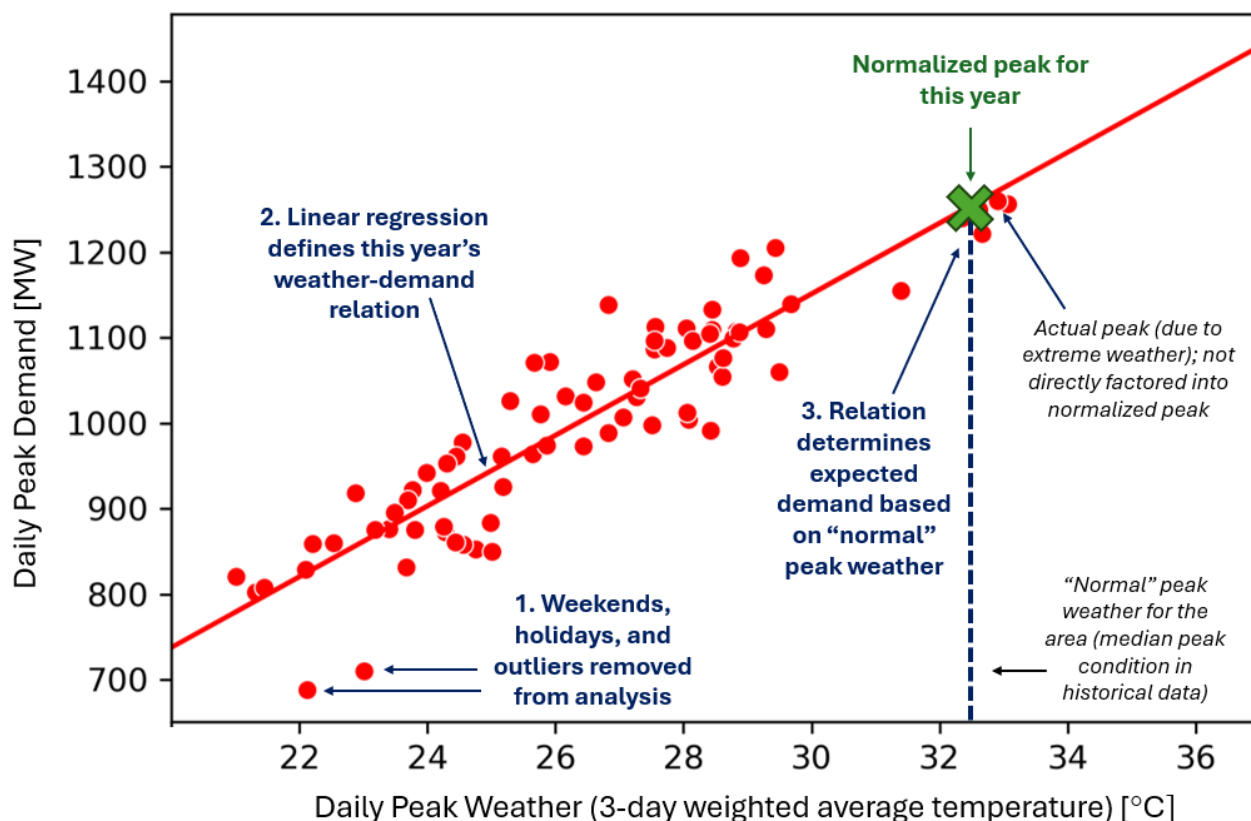
## 1.1 Method for Accounting for Weather Impact on Demand

Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historical electrical demand is weather-normalized. This section details the 3-step weather normalization process that is used.

Weather normalization is determined separately for each historical year. This is to allow for changes in the weather sensitivity from one year to the next. The previous 5 years were analysed, 2020 to 2024, and the summer and winter seasons were analysed separately for each year. The daily peak demand is collected for each year and season. For the summer season, the daily peak demand is plotted against a 3-day weighted average of daily *maximum* temperature. For the winter season, it is plotted against a 3-day weighted average of daily *minimum* temperature. Then the following process is used, which is illustrated in **Figure 1**.

1. Weekends, holidays, and outliers are removed.
2. A linear regression is performed.
3. The regression line is evaluated at the median temperature for the season.<sup>3</sup> The resulting value is used as the starting point for the year and season.

**Figure 1 | Method for Determining the Weather-Normalized Peak (Illustrative)**



<sup>3</sup> The median temperature for the season is found by taking the 30-year median of the annual worst 3-day weighted average temperature. For summer, worst means the maximum temperature; and for winter, worst means the minimum temperature.

The TWG used non-coincident peak demands for the starting points. As a result, the above-mentioned process was applied to the peak demand for each station.

## 2. Scope of Demand Forecast Scenarios

In response to the [Minister of Energy and Mines’ Integrated Energy Plan Implementation Directive for the IESO](#), the TWG has developed multiple forecast scenarios, which will be used to make plans adaptable to changes that may occur in the demand forecast between planning cycles. The TWG has produced a reference demand forecast, as well as a high growth and low growth scenario for consideration in this IRRP Addendum. The guideline for the reference forecast and two scenarios is provided below in **Table 1**.

**Table 1 | Demand Forecast and Scenarios Guideline**

Consideration	Reference Forecast	High Growth Scenario	Low Growth Scenario
Certainty of Project or Driver <sup>4</sup>	Reasonably certain	Could reasonably happen	Reasonably certain, but slower pacing or impact
Pacing of Load Buildup for Firm Requests <sup>5</sup>	As provided to LDCs	As provided to LDCs	Delayed or reduced
Pacing of Drivers	As provided to LDCs, or existing historical trends	As provided to LDCs, or highest historical trends	Low scenarios used when provided to LDCs, or lower historical trends
Demand Factors <sup>6</sup>	Average or mid-range values	Upper-range values	Lower-range values

## 3. Median-Weather Gross Demand Forecasts

Each of the five LDCs in the Burlington to Nanticoke Area provided their own reference forecast and scenarios for their own loads, corresponding to their service territories as illustrated in Figure 2. Forecasts and scenarios were provided as gross demand and assuming normal weather. The LDCs considered the same drivers, as detailed in Section 3.1.

<sup>4</sup> Driver refers to any input into the forecast that cannot be tied to a specific project, such as housing forecasts.

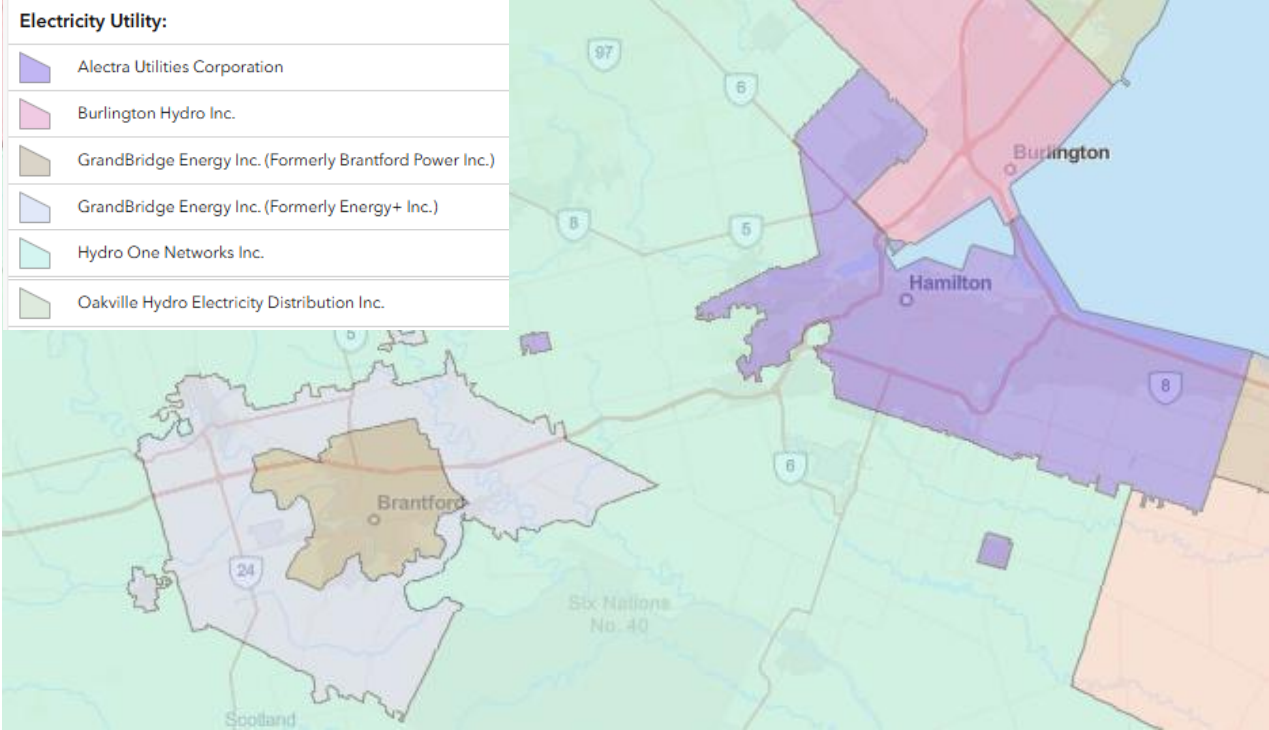
<sup>5</sup> Firm requests refer to confirmed load connection requests to the LDCs.

<sup>6</sup> Demand factors refer to any assumptions which translates quantities to electrical demand, such per-unit kW demand (ex kW/EV) or coincidence factors.

However, each LDC considered what was most appropriate for their customer base and their own historical trending, ultimately arriving at a forecast which reflects some uniqueness across their service territories. Sections 3.2 to 3.6 outline the variations in methodology used by each LDC.

For brevity, the use of the word “forecast” in the following sections will refer to both the reference forecast and the high and low growth scenarios, unless stated otherwise.

**Figure 2 | Map of the LDC Service Areas within the Burlington to Nanticoke Region**



**3.1 Common Drivers and Assumptions**

There are five drivers common across the LDC forecasts: firm requests, housing, industrial/commercial/institutional (IC&I) loads<sup>7</sup>, electric vehicles, and electric heating. As a result of forecasted electric heating loads, the Hamilton sub-region is forecasted to switch from summer-peaking to winter-peaking in 2033, approximately midway through the 20-year forecast period.

**3.1.1 Firm Requests**

Each LDC used firm requests<sup>8</sup> for connection to their system as an input into their forecast. Most often the requested demand is adjusted down due to factors such as overestimation and coincidence with the station peak. This factor was based on historical trends within each LDC’s customer base.

<sup>7</sup> The IC&I loads driver refers to additional ICI growth that is not already present as firm requests.

<sup>8</sup> A firm request is a committed connection request from a customer to an LDC, typically with a signed contract.

### 3.1.2 Housing and IC&I Loads

Every LDC included growth in housing and IC&I loads<sup>7</sup> as an input into their forecast. Housing forecasts provided by municipalities were used to forecast the quantity of new residential connections. IC&I load growth was informed by municipal inputs, developer engagement, and historical trends.

### 3.1.3 Electric Vehicles & Electric Heating

Every LDC considered electric vehicles and electric heating as an input into their forecast. All LDCs except for Grandbridge Energy Inc. ultimately included load growth from electric vehicles and electric heating in their forecasts. Grandbridge Energy Inc.'s assessment found that the impact of EVs and electric heating is insignificant relative to the rest of the load growth in its service territory.

Each LDC leveraged historical EV registration data from the Ontario Ministry of Transportation for their service territory, and used this to estimate EV growth trends. LDCs estimated potential uptake in electric heating based on national and municipal policies, and historical trends.

## 3.2 Alectra Utilities Corporation

Alectra Utilities Corporation ("Alectra") supplies power to a portion of the Region through the following stations (in part or in whole): Beach TS, Birmingham TS, Dundas 1 TS, Dundas 2 TS, Elgin TS, Gage TS, Horning TS, Kenilworth TS, Lake TS, Mohawk TS, Nebo TS, Newton TS, Stirton TS, and Winona TS. For a map of Alectra's service territory, please see **Figure 2** at the start of Section 3.

The Alectra Utilities long-term load forecast provides an indication as to where and how much the load increases are occurring. An increase in the peak demand is normally the biggest factor in driving the requirement for reinforcement of the system. Alectra Utilities performs a load forecasting exercise annually.

Alectra Utilities performs a combination of two methods of forecasting to determine the long-term system capacity adequacy assessment:

- End-use analysis using the latest information available from municipal report; and
- Past system peak performance and trend (statistical) analysis.

### 3.2.1 End-Use Analysis Using the Latest Information

Alectra Utilities reviews economic development and outlook for different regions that include Ontario Government development, population growth and job growth projections, municipal economic analysis report, past housing completion statistics and future housing projection, ICI building activities and news from media. Population, housing, and employment numbers were obtained from municipal development charge reports.

**Population Growth:** Historical annual population growth is obtained from Regional Annual Economic and Municipal Development Review Reports. Long-term annual population projection is obtained from provincial and municipal official plan reports published by Ontario government, and regional/municipal government.

**Employment Growth:** Historical employment and economic growth statistics reports published by Provincial and Municipal governments are used to extract the historic economic development and growth rates. Employment growth and structure projection are used to develop long-term employment forecast potentially categorized by the sector, industry and service types.

**Housing Activities:** Number of housing completions, mix of housing completions, vacancy rate and building permit activities in the Region and Municipal boundaries and residential developments plan are reviewed for long-term capacity need forecast. Plans of subdivision and condominiums are obtained and analyzed to develop the long-term load forecast.

**ICI Building Activity:** Industrial and Commercial development rate, commercial vacancy rate, industrial sale prices per square feet, total ICI construction and commercial/industrial building permits are obtained and compiled to develop the long-term load forecast for the region.

### 3.2.2 Weather Correction

Alectra uses weighted 3-day moving average temperature to correlate the peak demand and weather. Peak demand weather normalization is the process for estimating what peak demand would have occurred in a given time period if the weather had been normal (1 in 2). The weather normalized peak demand is used as the starting point for the forecast.

### 3.2.3 Other Factors

The other contributing factors to long-term load projections are CDM, DG contribution and other government incentives and programs (i.e. Global Adjustment), emerging industrial technologies (i.e. Microgrid, battery storage, CHP, etc.), newly introduced load types (i.e., electric vehicles, fleets) that are reviewed and assessed in load forecast procedure.

### 3.2.4 Electrification of Transportation and Decarbonization

Alectra Utilities continues to monitor the uptake of EV vehicles and projects related to electrification of transportation to better understand and determine the impact on local electricity needs. Alectra Utilities uses the available information on EV adoption and evaluates the impact of the EV's at the peak. The impact of existing and new buildings decarbonization in Alectra service area is also considered.

### 3.2.5 Past System Peak Performance and Trend Analysis

The trend analysis is performed to forecast the system peak from historical peak demand results. The purpose of the trend analysis is to compare the results with end-use method to obtain more realistic long-term load projections considering the historical demand peak.

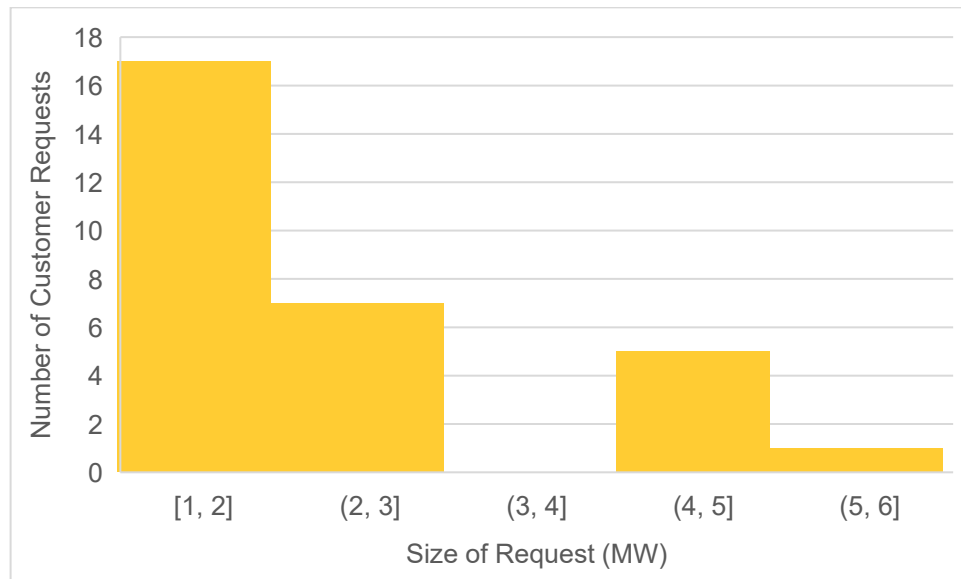
### 3.2.6 Customer Requests

Alectra Utilities has received over 30 customer connection requests exceeding 1 MW, and has included these loads in its load forecast. The majority of these requests are in the range of 1-6 MW, as shown in **Figure 3**. In addition to these, Alectra Utilities has received several larger requests which have also been included in its forecast, as follows:

- Customer #1: 140 MW,

- Customer #2: 60 MW,
- Customer #3: 25 MW, and
- Customer #4: 15 MW.

**Figure 3 | Histogram of Customer Requests (1-6 MW) Included in Alectra Utilities' Forecast**



### 3.3 Hydro One Networks Inc. (Distribution)

Hydro One Distribution (“HONI”) supplies power to a portion of the Region through the following stations (in part or in whole): Bloomsburg DS, Brant TS, Caledonia TS, Dundas 1 TS, Dundas 2 TS, Jarvis TS, Nebo TS, and Norfolk TS. For a map of HONI’s service territory, please see **Figure 2** at the start of Section 3.

#### 3.3.1 Forecast Methodology and Assumptions

Hydro One Distribution used both econometric and end-use forecasting to develop the load forecast for Hamilton Area Regional Planning. A baseline forecast (MW station peak in the base year) was developed, considering factors as normal operating conditions and coincident peak loading.

For the Hamilton Area forecast, Hydro One Distribution used the weather corrected peak demand levels for the station serving Hydro One customers. From the established baseline year, a growth rate (%) was applied to station demand level to provide forecast values within the study timeframe.

Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW/sq. ft); and electrification trends (e.g., more vehicles switching from gas to electrical vehicles). Based on Hydro One’s latest residential survey, the following adoption rates for Electric Vehicles (EV) and heat pumps were used in the Hamilton region, and applied to the baseline forecast:

- The EV penetration in the Hamilton region is 6.3% with an additional 2.5% Plug-in hybrid cars (PHEV).
- 4% of Hydro One distribution customers are using geothermal heat pumps as the primary type of heating equipment in their homes.

The above adoption rates resulted in the following EV and Electrification share of Hydro One Distribution’s baseline forecast, across distribution’s low, reference, and high scenarios:

<b>Scenario</b>	<b>Year</b>	<b>EV (% of Load)</b>	<b>Electrification (% of Load)</b>
<b>Low</b>	2035	8.1	1.5
	2045	16.1	2.1
<b>Reference</b>	2035	8.4	1.7
	2045	16.9	2.6
<b>High</b>	2035	8.7	1.9
	2045	17.7	3.2

Where possible, detailed information about load growth, based on local knowledge and/or municipal/provincial energy plans, was used to augment the forecast values within the study period.

HONI included several large firm requests in its forecast, as listed below. HONI used municipal plans, input from field staff, and input from developers to forecast its IC&I load, as well as large residential developments in the area. Specific IC&I developments provided from municipal input include the Airport Employment Growth District (AEGD) and Red Hill Business Park.

- IC&I Customer #1: 2 MW
- IC&I Customer #2: 1 MW
- IC&I Customer #3: 6 MW
- IC&I Customer #4: 5 MW
- IC&I Customer #5: 10 MW
- IC&I Customer #6: 1 MW
- IC&I Customer #7: 2 MW
- IC&I Customer #8: 2 MW
- IC&I Customer #9: 10 MW
- IC&I Customer #10: 2 MW
- IC&I Customer #11: 2 MW
- Residential Development #1: 1 MW
- Residential Development #2: 1 MW

### 3.4 GrandBridge Energy Inc.

GrandBridge Energy Inc. ("GBE") supplies power to a portion of the Region through the following stations (in part or in whole): Brant TS, Brantford TS, and Powerline MTS. For a map of GBE's service territory, please see **Figure 2** at the start of Section 3.

### **3.4.1 Forecast Methodology and Assumptions**

GrandBridge Energy (GBE) considered all of the common drivers in its forecast. Forecasted residential growth per year was based on annual housing unit projections outlined in City of Brantford and County of Brant development charges studies. Forecasted non-residential growth per year was based on annual gross floor area (square metres) projections outlined in City of Brantford and County of Brant development charges studies. In order to convert residential housing unit numbers into kW, an actual average value was used based on smart meter readings from a recent residential subdivision. Similarly, to convert non-residential gross floor area (square metres) values into kW, an average value of kW per square metre was used based on a group of existing buildings. A 19.6 MW industrial customer request was included in the load forecast.

The City of Brantford and the County of Brant are anticipating over 23,000 new residential housing units between 2026 and 2045. The City of Brantford and the County of Brant are anticipating about 2.1 million square metres of new non-residential development between 2026 and 2045.

The Provincial Planning Statement (PPS), 2024 identifies the City of Brantford in its list of "Large and Fast-Growing Municipalities". The land area of the City of Brantford expanded by 6,700 hectares in 2017 as result of its boundary expansion. This area is planned for residential and non-residential development.

GBE considered the impact of electric vehicles. With an expected coincident peak demand impact between 0.6 and 1.7kW per EV in a reference forecast, a much larger adoption rate of electric vehicles would have to occur in order to have a significant impact on coincident peak demand. The high forecast would capture a higher electric vehicle adoption rate.

GBE considered the impact of residential and non-residential customers switching from fossil fuel to electricity as the energy source for heating and/or industrial processes. No specific numbers were incorporated into the summer peak forecast given the uncertainty in the magnitude and timing. The greatest impact of residential heating changes to electricity would be in the winter. GBE did increase its winter forecast growth rate and forecasted that the reference winter peak would equal the reference summer peak in 2044. The high summer and winter forecasts would capture additional electrification. The summer peak is expected to remain the constraint due to lower equipment ratings during hot weather.

## **3.5 Burlington Hydro Inc.**

Burlington Hydro Inc. ("BHI") is an LDC supplying power within the City of Burlington through the following stations (in part or in whole): Bronte TS, Burlington TS, and Cumberland TS. For a map of BHI's service territory, please see **Figure 2** at the start of Section 3.

### **3.5.1 Forecast Methodology and Assumptions**

BHI considered all of the common drivers in its forecast and used a blend of both econometric and end-use forecasting to produce its forecast. Demand growth is primarily driven by residential load growth, followed by IC&I load growth.

BHI included firm connection requests in its forecast, with the estimated per/unit demand listed below as well as SPA data from City of Burlington. Where appropriate, requested demand values were adjusted to reflect expected realization of load over the planning horizon and coincidence with station peak demand, based on historical experience.

- Residential complex #1: 2.5 MW
- Residential complex #2: 3 MW
- Residential complex #3: 3 MW
- Residential complex #4: 2 MW
- Commercial/Industrial #5: 3.5 MW
- Commercial/Industrial #6: 5 MW
- Commercial/Industrial #7: 20 MW

Incremental IC&I load growth not already reflected in firm requests was included in the forecast. IC&I growth assumptions were informed by municipal planning documents, employment forecasts, and historical trends. Scenario variation reflects uncertainty in both development pacing and load intensity.

Housing load growth was forecasted based on projected household growth within the City of Burlington based on the Housing Strategy and Community Improvement Plan. Consistent with municipal planning inputs and developer information for in-progress projects, growth is concentrated in identified intensification areas, with MUR (multi-unit-residential) buildings assumed as having lower average coincident peak contributions than ground-related housing forms. The latest Municipal input included population rise to 212,000 by 2031 and 265,000 by 2051, and approximate increase of just under 1,200 residential units per year over the forecast period.

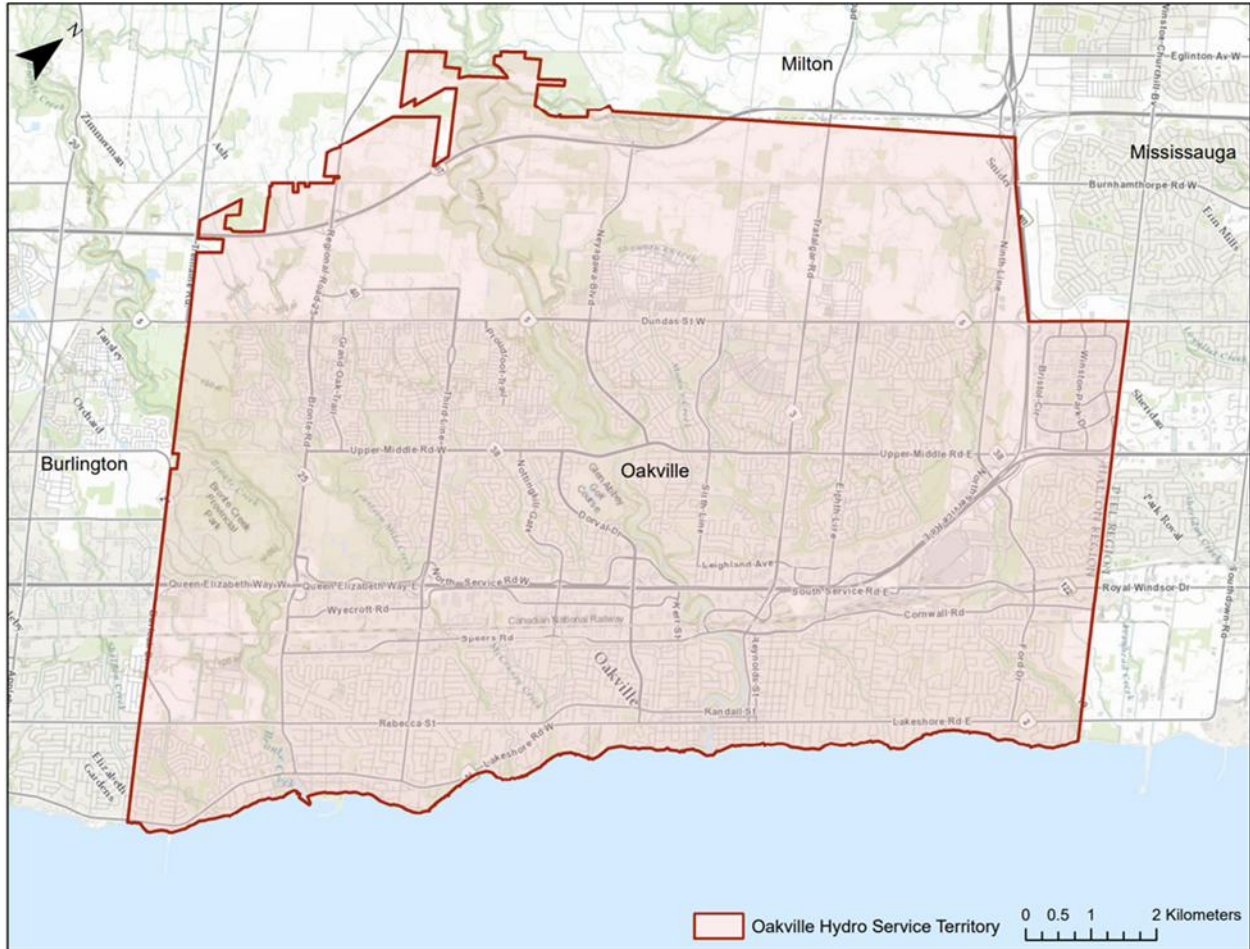
BHI used historical EV registration data from the Ontario Ministry of Transportation for their service territory and Electrical Safety Authority to estimate the existing number of EVs in its service territory. For its reference forecast, BHI used a trending analysis of historical EV adoption to forecast future adoption. This resulted in an adoption of 23% in 2034, and 38% in 2044. For its high growth scenario an adoption of 53% in 2034 and 83% in 2044.

Electrification of space heating, primarily through heat pump adoption, was included as an emerging demand driver. Adoption assumptions were informed by municipal climate planning and broader provincial decarbonization objectives, with impacts modelled separately for summer and winter peaks. BHI assumed heat pump adoption for both residential and IC&I customers, but only for new connections. For residential customers, this resulted in 14% of new connections by 2034, and 42% of new connections by 2044. For IC&I customers, this resulted in 9% of new connections by 2034, and 35% of new connections by 2044.

### **3.6 Oakville Hydro Electricity Distribution Inc.**

Oakville Hydro (“OH”) is the local distribution company supplying electricity to over 77,000 individuals, families and businesses in the Town of Oakville. OH’s service area is supplied through five transformer stations (TS): Bronte TS, Oakville TS, Trafalgar TS, Palermo TS, and Glenorchy MTS. Within the Burlington to Nanticoke Region, OH’s demand is represented at Bronte TS. For a map of OH’s service area, please see **Figure 2** at the start of Section 3, and **Figure 4** for more detail below.

**Figure 4 | Oakville Hydro Service Territory**



### 3.6.1 Forecast Methodology and Assumptions

OH’s demand forecast was developed using a bottom-up approach, with load growth modeled at the feeder level and aggregated to municipal station (MS), transformer station (TS), and system levels to support long-term capacity planning. Historical daily peak loads were weather-normalized using a multivariate regression model.

The OH forecast indicates continued demand growth across the service territory, with near-term supply pressures emerging in the Bronte TS area. In the near term, system flexibility and load transfers are expected to support growth, while longer-term solutions will require coordination with Hydro One and the IESO.

Known large customer connections and high-probability developments were included where appropriate, while broader IC&I growth was informed by municipal planning inputs, developer engagement, and historical trends. OH included several large customer requests, consisting primarily of institutional and industrial developments, with individual project sizes ranging from approximately 5 MW to 8 MW. Specific growth areas provided from municipal input include: Bronte Village, Downtown Oakville, Kerr Village, Midtown Oakville, Palermo Village, and Uptown Core over the forecast period.

- IC&I Customer #1: 8 MW
- IC&I Customer #2: 7.5 MW
- IC&I Customer #3: 7.5 MW
- IC&I Customer #4: 5 MW

Residential and commercial growth was based on municipal housing and employment forecasts and translated into peak demand using representative load impacts by customer class and archetype. Over the 2025–2050 forecast horizon, approximately 81,000 new residential units are projected across the OH service area. Load growth assumptions reflect development across key areas of the Town of Oakville, including Midtown Oakville, Uptown Core, Downtown Oakville, Kerr Village, Palermo Village, and Bronte Village.

Electric vehicle (EV) charging demand forecast was developed using a range of adoption scenarios informed by current adoption levels and expected uptake patterns. EV adoption is expected to increase across all scenarios, reaching approximately 10% to 30% by 2041. Building electrification was included for both new construction and retrofits, informed by national and municipal policy. By 2041, residential electrification is projected to reach approximately 40% to 80%, while commercial electrification is projected to reach approximately 30% to 60%, depending on the scenario. Customer growth is expected to be the primary driver of demand increases, with EV adoption and building electrification contributing increasingly to peak demand over time, particularly for winter peaks.

## 4. Forecasted Distributed Generation

Distributed generation refers to any generation connected to the distribution system, rather than the transmission system. The DG forecast includes all DGs that have a contract with the IESO, up until their contract expiry date, at which point the DG is assumed to be removed from service.<sup>9</sup> Non-contract DGs were assumed to persist to the end of the forecast period (20 years). Capacity factors from the 2025 Summer and Winter Peak Capacity Contribution<sup>10</sup> from the IESO's 2025 Annual Planning Outlook were used.

## 5. Electricity Demand Side Management Assumptions

Electricity demand side management (eDSM) measures can reduce the electricity demand, and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and

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<sup>9</sup> This assumption may be revisited during the Options Analysis component of the IRRP, if recontracting expired DG can be part of a viable solution.

<sup>10</sup> See Figure 2 within the [Supply, Adequacy and Energy Outlook Module Data](#) of the 2025 Annual Planning Outlook

DSM programs. The assumptions used for the Hamilton Area Addendum forecast are consistent with the DSM assumptions in the IESO's 2026 Annual Planning Outlook including the 2025 – 2027 DSM Framework and anticipated long term program savings beyond that. The savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top-down approach was used to estimate peak demand savings from the provincial level to the Southwest IESO transmission zone and then allocated to the Burlington to Nanticoke region (which includes the Hamilton sub-region). This section describes the process and methodology used to estimate eDSM savings for the Burlington to Nanticoke region and provides more detail on how the savings for the two categories were developed.

## **5.1 Factors that Affect Electricity Demand**

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the Southwest transmission zone and compared with the gross peak demand forecast for each zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region, as further described below.

Consistent with the gross demand forecast, 2025 was used as the reference year. New peak demand savings from codes and standards were estimated from 2026 to 2045. The residential annual peak reduction percentages for each year were applied to the forecast residential peak demand at each station to develop an estimate of peak demand impacts from codes and standards. The same is done for the commercial sector. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. It is assumed that there is no saving from codes and standards associated with the industrial sector.

## **5.2 Forecast Methodology and Assumptions**

In addition to codes and standards, the delivery of eDSM programs reduces electricity demand. The impact of existing and planned eDSM programs were analyzed, which include the 2025 – 2027 DSM Framework and the assumed continuation of provincial programs beyond 2027 at savings levels consistent with the current framework adjusted for gross demand growth. A top-down approach was used to estimate the peak demand reduction due to the delivery of these programs, from the province to the Southwest transmission zone, and finally to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages from program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in the Southwest transmission zone. They were then applied to the sectoral gross peak forecast of each station in the region.

### 5.3 Estimated Savings from DSM Programs

As described in the above sections, peak demand savings were estimated for each sector and totalled for each station in the region. The analyses were conducted under normal weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analysis.

## 6. Final Peak Forecast by Station

### 6.1 Forecasted Extreme Temperature

According to Section 2.4.10.1, Load Security Criteria, of the [Ontario Resource and Transmission Assessment Criteria](#) (ORTAC), “the transmission system must be planned to satisfy demand levels up to the extreme weather”. As a result, extreme weather forecasts are used to assess needs in the IRRP.

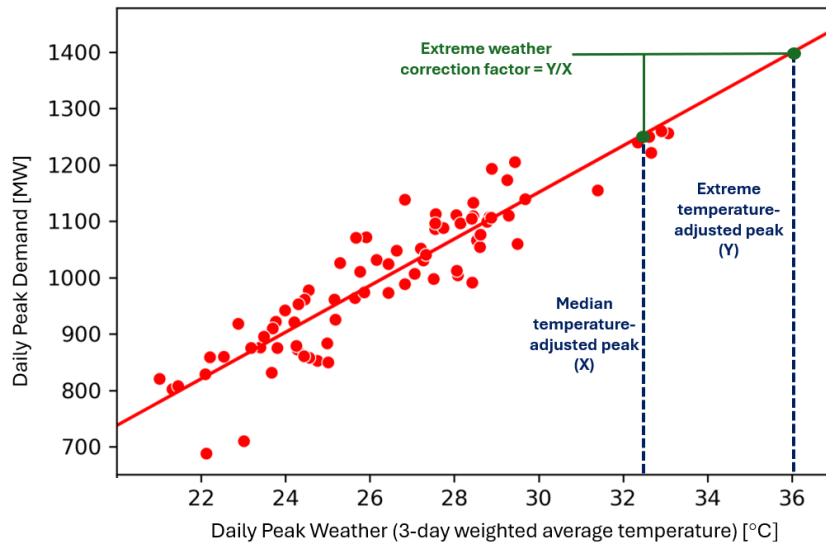
To produce extreme weather forecasts, first extreme temperatures are defined. Following this, the median-weather gross demand forecasts are converted into an extreme-weather gross forecasts by the processes discussed next in Sections 6.2 and 6.3.

For the summer, the extreme temperature is defined as the highest 3-day weighted average temperature observed over the last 30 years (approximately 97<sup>th</sup> percentile of annual peak temperature). For the winter, the extreme temperature is defined as the lowest 3-day weighted average temperature observed over the last 30 years.

### 6.2 Extreme-weather Gross Coincident Forecast

1. As discussed in Section 1.1, a linear regression is performed for the regional daily peak demand against the 3-day weighted average of the appropriate temperature (maximum or minimum) for each historical year and season. As illustrated in **Figure 5**, the fitted line is evaluated at the extreme temperature and the median temperature. The quotient of these two values is the value of the extreme-weather coincident factor for that historical year and season.
2. The average of the historical extreme-weather coincident factors is taken, and multiplied by the median-weather gross coincident demand forecast. This produces the extreme-weather gross coincident forecast.

**Figure 5 | Method for Determining Extreme-Weather Factor (Illustrative)**



### 6.3 Extreme-weather Gross Non-coincident Forecast

This process is conceptually similar to that in the previous subsection 6.2, but with the approach taken applied to each station individually.

1. As discussed in Section 1.1, a linear regression is performed for the station daily peak demand against the 3-day weighted average of the appropriate temperature (maximum or minimum) for each historical year and season.
2. The fitted line is evaluated at the extreme temperature, and then divided by the median-weather non-coincident peak demand of the station for the historical year and season. The result is the value of the extreme-weather non-coincident factor for that historical year and season.
3. The average of the historical extreme-weather non-coincident factors is taken, and multiplied by the median-weather gross non-coincident demand forecast. This produces the extreme-weather gross non-coincident forecast.

### 6.4 Final Peak Forecast

The final peak demand forecasts were produced by taking the extreme-weather gross demand forecasts and applying the forecasted DG and the eDSM assumptions. eDSM savings are assumed to be the same for both coincident and non-coincident forecasts.