# SUMMARY OF REVENUE REQUIREMENT

## 1.0 INTRODUCTION

The revenue requirements presented below for Transmission, Section 2.0, and for Distribution, Section 3.0, represent the amounts required by Hydro One to safely and reliably serve customers. They align with customer needs and preferences and allow for responsible stewardship of assets that constitute critical infrastructure, all while balancing impacts on rates. Furthermore, the revenue requirements for Transmission and Distribution proposed in the current application incorporate Hydro One's upfront commitment to deliver efficiencies and improved productivity to customers.

The Transmission revenue requirement proposed is necessary to achieve outcomes that are valued by customers and required to sustain safe and reliable transmission system operations, maintain equipment performance and fund investments necessary to address system needs and service obligations, and invest in infrastructure that is essential to core business functions and operations.

The Distribution revenue requirement proposed represents the funding necessary to serve the approximately 1.5M residential, commercial, industrial and LDC customers across the province of Ontario who rely on Hydro One's distribution system for their power supply. It will allow Hydro One to undertake the investments, and operations, maintenance and administration expenditures necessary to provide safe and reliable distribution of power and sufficient grid capacity to accommodate customer demand and align with customer preferences.

Both the Transmission and Distribution revenue requirements reflect customer needs and preferences identified through a comprehensive two-phase customer engagement process. Further details regarding Hydro One's customer engagement activities are provided in SPF Section 1.6.

Section 2.0 begins by summarizing the revenue requirement proposed by Hydro One for Transmission for the 2028 rebasing year. The remaining Transmission sections address individual components of the calculation of the Transmission revenue requirement in the 2028 rebasing year. Attachments 1-5 to this Exhibit provide the full details of the Transmission revenue requirement for each year in the rate period (2028 to 2032).

Section 3.0 begins by summarizing the revenue requirement proposed by Hydro One for Distribution. The remaining Distribution sections address individual components of the calculation of the Distribution revenue requirement in the 2028 rebasing year. Attachments 6-10 to this Exhibit provide the full details of the Distribution revenue requirement for each year in the rate period (2028 to 2032).

## 2.0 SUMMARY OF TRANSMISSION REVENUE REQUIREMENT

Hydro One has calculated its Transmission revenue requirement using the approaches and methodologies applied and accepted in previous OEB proceedings. The results of these calculations are summarized in Table 1.

**Table 1 - Transmission Revenue Requirement ($M)[1]**

| Components | 2023 OEB-Approved Note 1 | 2024 Note 2 | 2025 Note 3 | 2026 Note 4 | 2027 Note 5 | 2028 Test Year | Reference |
|---|---|---|---|---|---|---|---|
| OM&A | 433.7 | - | - | - | - | 634.5 | Exhibit E-02-01 |
| Depreciation and Amortization | 531.3 | - | - | - | - | 738.4 | Exhibit E-08-01 |
| Income Taxes | 65.2 | - | - | - | - | 103.7 | Exhibit E-09-02 Attachment 1 |
| Return on Capital | 922.2 | - | - | - | - | 1,250.1 | Exhibit F-01-03 |
| **Total Revenue Requirement** | **1,952.5** | **2,079.8** | **2,174.5** | **2,282.5** | **2,363.3** | **2,726.6** | |

*Note 1: Represents OEB-approved 2023 revenue requirement in EB-2021-0110*
*Note 2: Represents OEB-approved 2024 revenue requirement in 2024 Annual Update in EB-2023-0127*
*Note 3: Represents OEB-approved 2025 revenue requirement in 2025 Annual Update in EB-2024-0217*
*Note 4: Represents OEB-approved 2026 revenue requirement in 2026 Annual Update in EB-2025-0159*
*Note 5: 2027 revenue requirement = $2,282.5M (2026 Revenue Requirement) * (1 + (2.90% inflation factor – 0.15% stretch factor + 0.79% capital factor)) = $2,363.3M. 2027 OEB approved revenue requirement to be established as part of the 2027 Annual Update in EB-2026-0169.*

[1] Figures presented in the tables may not sum to the totals shown due to rounding

## 2.1 CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

The details of the Transmission Revenue Requirement components are as follows:

### 2.1.1 TRANSMISSION OM&A

The calculation of the Transmission OM&A Expense that forms part of the Transmission Revenue Requirement is shown below in Table 2.

**Table 2 - Transmission OM&A Expense ($M)**

| | 2028 | Reference |
|---|---|---|
| Sustainment | 305.9 | Exhibit E-02-02 |
| Development | 13.0 | Exhibit E-02-03 |
| Customer Care | 6.8 | Exhibit E-02-04 |
| Common and Other | 219.1 | Exhibit E-04-01 |
| Property Taxes and Rights Payments | 89.7 | Exhibit E-09-06 |
| **Total OM&A for Revenue Requirement** | **634.5** | Exhibit E-02-01 |

Further details on the OM&A components are provided in the exhibit references identified in Table 2 above.

### 2.1.2 TRANSMISSION DEPRECIATION AND AMORTIZATION

The calculation of the Depreciation and Amortization Expense that forms part of the Transmission Revenue Requirement is shown below in Table 3.

**Table 3 - Transmission Depreciation and Amortization Expense ($M)[2]**

| | 2028 | Reference |
|---|---|---|
| Depreciation | 713.8 | |
| Amortization | 0.4 | |
| Cloud Computing Amortization and Return on Cloud | 24.1 | |
| **Total Expense for Revenue Requirement** | **738.4** | Exhibit E-08-01 |

[2] Figures presented in the tables may not sum to the totals shown due to rounding.

### 2.1.3 TRANSMISSION INCOME TAXES

The calculation of the Corporate Income Taxes that form part of the Transmission Revenue Requirement is shown below in Table 4.

**Table 4 - Transmission Corporate Income Taxes ($M)**

| | 2028 | Reference |
|---|---|---|
| Regulatory Taxable Income | 392.5 | |
| Tax Rate | 26.5% | |
| **Subtotal** | **104.0** | |
| Less: Tax Credits | (0.3) | |
| **Total Income Taxes** | **103.7** | Exhibit E-09-02 Attachment 1 |

### 2.1.4 TRANSMISSION RETURN ON CAPITAL

The calculation of the Return on Capital that forms part of the Transmission Revenue Requirement is shown below in Table 5.

**Table 5 - Transmission Return on Capital ($M)**

| | 2028 | Reference |
|---|---|---|
| Debt Cost | 463.0 | |
| Return on Equity | 787.1 | |
| **Return on Capital** | **1,250.1** | Exhibit F-01-03 |

## 2.2 TRANSMISSION REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

### 2.2.1 2028 COMPARED TO 2027

The Transmission revenue requirement for 2027 ($2,363.3M) is shown in Table 1 above.[3] The proposed 2028 Transmission revenue requirement represents an increase of 15.4% as compared to the 2027 forecast, or about $363.3M. This increase is predominantly driven by an increase in OM&A (see Exhibit E-02-01) and higher rate base growth resulting in higher return on equity (see Exhibit F-01-03) and higher depreciation expense (see Exhibit E-08-01).

[3] EB-2026-0169, 2027 HONI Transmission Annual Update Application, Exhibit A-04-01, Table 4

### 2.2.2 2028 COMPARED TO 2023

Table 6 below shows the key drivers of the increase in the 2028 test year Transmission revenue requirement. The dollar amounts and percentage changes are obtained by comparing the 2028 test year components with the corresponding approvals received in the last rebasing year in 2023 (per EB-2021-0110). The 2023 year is used as the basis for this line-by-line comparison, as it represents the last approved rebasing year for Hydro One Transmission.

This increase is predominantly driven by rate base growth (see Exhibit C-01-01) and higher OM&A (see Exhibit E-02-01).

**Table 6 - Impact of Individual Components on Transmission Revenue Requirement**

| Description | 2028 vs. 2023 | 2028 vs. 2023 |
|---|---|---|
| | ($M) | (%) |
| Rate Base Growth | 475.4 | 24% |
| Increase in OM&A | 200.7 | 10% |
| Capital Structure Change | 44.1 | 2% |
| Cloud Computing Amortization and Return | 24.1 | 1% |
| Taxes and Other Changes | 29.8 | 2% |
| **Impact on Revenue Requirement** | **774.1** | **40%** |

## 2.3 SUMMARY OF DISTRIBUTION REVENUE REQUIREMENT

Hydro One has calculated its Distribution revenue requirement using the approaches and methodologies applied and accepted in previous OEB proceedings. The results of these calculations are summarized in Table 7.

**Table 7 - Distribution Revenue Requirement ($M)[4]**

| Components | 2023 OEB-Approved Note 1 | 2024 Note 2 | 2025 Note 3 | 2026 Note 4 | 2027 Note 5 | 2028 Test Year | Reference |
|---|---|---|---|---|---|---|---|
| OM&A | 616.3 | - | - | - | - | 958.7 | Exhibit E-03-01 |
| Depreciation and Amortization | 461.4 | - | - | - | - | 753.7 | Exhibit E-08-01 |
| Income Taxes | 53.7 | - | - | - | - | 42.7 | Exhibit E-09-02 Attachment 1 |
| Return on Capital | 595.8 | - | - | - | - | 939.8 | Exhibit F-01-03 |
| **Total Revenue Requirement** | **1,727.2** | **1,819.8** | **1,892.6** | **1,991.2** | **2,073.4** | **2,694.8** | |

*Note 1: Represents OEB-approved 2023 revenue requirement in EB-2021-0110*
*Note 2: Represents OEB-approved 2024 revenue requirement in 2024 Annual Update in EB-2023-0030*
*Note 3: Represents OEB-approved 2025 revenue requirement in 2025 Annual Update in EB-2024-0032*
*Note 4: Represents OEB-approved 2026 revenue requirement in 2026 Annual Update in EB-2025-0030*
*Note 5: 2027 revenue requirement = $1,991.2M (2026 Revenue Requirement) * (1 + (3.00% inflation factor – 0.45% stretch factor + 1.58% capital factor)) = $2,073.4M. 2027 OEB approved revenue requirement to be established as part of the 2027 Annual Update in in EB-2026-0049.*

## 2.4 CALCULATION OF DISTRIBUTION REVENUE REQUIREMENT

The details of the Distribution Revenue Requirement components are discussed in the following sections.

### 2.4.1 DISTRIBUTION OM&A

The calculation of the Distribution OM&A Expense that forms part of the Distribution Revenue Requirement is shown below in Table 8.

**Table 8 - Distribution OM&A Expense ($M) [5]**

| | 2028 | Reference |
|---|---|---|
| Sustainment | 523.0 | Exhibit E-03-02 |
| Development | 17.6 | Exhibit E-03-03 |
| Customer Care | 139.6 | Exhibit E-03-04 |
| Common and Other | 271.1 | Exhibit E-04-01 |
| Property Taxes and Rights Payments | 7.5 | Exhibit E-09-06 |
| **Total OM&A for Revenue Requirement** | **958.7** | Exhibit E-03-01 |

[4] Figures presented in the tables may not sum to the totals shown due to rounding.
[5] Figures presented in the tables may not sum to the totals shown due to rounding.

Further details on the OM&A components are provided in the exhibit references identified in Table 8 above.

### 2.4.2 DISTRIBUTION DEPRECIATION AND AMORTIZATION EXPENSE

The calculation of the Depreciation and Amortization Expense that forms part of the Distribution Revenue Requirement is shown below in Table 9.

**Table 9 - Distribution Depreciation and Amortization Expense ($M)**

| | 2028 | Reference |
|---|---|---|
| Depreciation | 707.4 | |
| Amortization | 0.3 | |
| Cloud Computing Amortization and Return on Cloud | 46.0 | |
| **Total Expense for Revenue Requirement** | **753.7** | E-08-01 |

### 2.4.3 DISTRIBUTION INCOME TAXES

The calculation of the Corporate Income Taxes that form part of the Distribution Revenue Requirement is shown below in Table 10.

**Table 10 - Distribution Corporate Income Taxes ($M)[6]**

| | 2028 | Reference |
|---|---|---|
| Regulatory Taxable Income | 180.0 | |
| Tax Rate | 26.5% | |
| **Subtotal** | **47.7** | |
| Less: Tax Credits | (0.2) | |
| Add: Broadband Taxable Income Tax | (4.8) | |
| **Total Income Taxes** | **42.7** | Exhibit E-09-02 Attachment 1 |

### 2.4.4 DISTRIBUTION RETURN ON CAPITAL

The calculation of the Return on Capital that forms part of the Distribution Revenue Requirement is shown below in Table 11.

[6] Figures presented in the tables may not sum to the totals shown due to rounding.

**Table 11 - Distribution Return on Capital ($M)**

| | 2028 | Reference |
|---|---|---|
| Debt Cost | 348.0 | |
| Return on Equity | 591.7 | |
| **Return on Capital** | **939.8** | Exhibit F-01-03 |

## 2.5 DISTRIBUTION REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

### 2.5.1 2028 COMPARED TO 2027

The Distribution revenue requirement for 2027 ($2,073.4M) is shown in Table 7 above.[7] The proposed 2028 Distribution revenue requirement represents an increase of about 30.0% compared to the 2027 forecast or about $621.4M. This increase is predominantly driven by an increase in OM&A (see Exhibit E-03-01) and higher rate base (see Exhibit C-01-01), which results in higher depreciation (see Exhibit E-08-01) and return on equity (see Exhibit F-01-03). The higher rate base reflects investments necessary to provide safe and reliable distribution of power and sufficient grid capacity to accommodate customer demand, as well as align with customer preferences.

### 2.5.2 2028 COMPARED TO 2023

Table 12 below shows the key drivers of the increase in the 2028 test year Distribution revenue requirement. The dollar amounts and percentage changes are obtained by comparing the 2028 test year components with the corresponding approvals received in the last rebasing year in 2023 (per EB-2021-0110). The 2023 year used as the basis for this line-by-line comparison, instead of 2027, as it represents the last approved rebasing year for Hydro One Distribution.

The increase in revenue requirement is predominantly driven by rate base growth (see Exhibit C-01-01) and higher OM&A (see Exhibit E-03-01).

[7] EB-2026-0049, 2027 HONI Dx Application, Exhibit A-04-02, Table 3

**Table 12 - Impact of the Individual Component on Distribution Revenue Requirement[8]**

| Description | 2028 vs. 2023 OEB-Approved ($M) | 2028 vs. 2023 OEB-Approved (%) |
|---|---|---|
| Rate Base Growth | 558.7 | 32% |
| Increase in OM&A | 342.4 | 20% |
| Cloud Computing Amortization | 46.0 | 3% |
| Capital Structure Change | 33.2 | 2% |
| Taxes and Other | (12.6) | (1%) |
| **Impact on Revenue Requirement** | **967.6** | **56%** |

[8] Figures presented in the tables may not sum to the totals shown due to rounding

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# 2028 TRANSMISSION REVENUE REQUIREMENT

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# 2028 DISTRIBUTION REVENUE REQUIREMENT

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# 2032 DISTRIBUTION REVENUE REQUIREMENT

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# SUMMARY OF REVENUE REQUIREMENT - HOSSM

## 1.0 INTRODUCTION

The revenue requirements presented below for HOSSM represent the amounts required to safely and reliably serve customers. They align with customer needs and preferences and allow for responsible stewardship of assets that constitute critical infrastructure, all while balancing impacts on rates.

Section 2 summarizes the revenue requirement requested by HOSSM for the 2027 and 2028 test years. Attachments 1-6 to this Exhibit provide full details of the HOSSM revenue requirement for each year in the rate period (2027 to 2032).

## 2.0 SUMMARY OF HOSSM REVENUE REQUIREMENT

Hydro One has calculated its HOSSM revenue requirement using the approaches and methodologies applied and accepted in previous OEB proceedings. The results of these calculations are summarized in Table 1.

**Table 1 - HOSSM Revenue Requirement ($M)[1]**

| Components | 2016 OEB Approved Note 2 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 Test Year | 2028 Test Year | Reference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | 11.4 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 10.6 | 10.9 | E-02-06 |
| Depreciation and Amortization | 9.8 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 13.0 | 14.3 | E-08-02 |
| Income Taxes | 2.1 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 0.1 | 0.4 | E-09-04 |
| Return on Capital | 16.6 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 22.4 | 24.3 | F-02-03 |
| **Total Revenue Requirement** | **39.9** | **39.9** | **39.9** | **40.3** | **40.9** | **41.6** | **42.5** | **44.0** | **46.2** | **47.8** | **49.4** | **46.1** | **50.0** | |

## 2.1 CALCULATION OF HOSSM REVENUE REQUIREMENT

The details of the HOSSM revenue requirement components are as follows:

### 2.1.1 HOSSM OM&A

The calculation of the HOSSM OM&A Expense that forms part of the revenue requirement is shown below in Table 2.

**Table 2 - HOSSM OM&A Expense ($M)**

| | 2027 | 2028 | Reference |
|---|---|---|---|
| Sustainment | 8.5 | 9.1 | E-02-06 |
| Common and Other | 2.1 | 1.8 | E-02-06 |
| **Total OM&A for Revenue Requirement** | **10.6** | **10.9** | |

Further details on the OM&A components are provided in the exhibit references identified in Table 2 above.

### 2.1.2 HOSSM DEPRECIATION AND AMORTIZATION

The calculation of the Depreciation and Amortization Expense that forms part of the HOSSM revenue requirement is shown below in Table 3.

[1] Figures presented in the tables may not sum to the totals shown due to rounding
[2] Excludes “Other Revenue” that is not part of the Service Revenue Requirement in 2016 GLPT application, escalated every year for Revenue Cap Index (RCI) based on OEB-approved inflation factor

**Table 3 - HOSSM Depreciation and Amortization Expense ($M)**

| | 2027 | 2028 | Reference |
|---|---|---|---|
| Depreciation and Amortization Expense | 13.0 | 14.3 | |
| **Total Expense for Revenue Requirement** | **13.0** | **14.3** | E-08-02 |

### 2.1.3 HOSSM INCOME TAXES

The calculation of the Corporate Income Taxes that form part of the HOSSM revenue requirement is shown below in Table 4.

**Table 4 - HOSSM Corporate Income Taxes ($M)**

| | 2027 | 2028 | Reference |
|---|---|---|---|
| Regulatory Taxable Income | 0.3 | 1.5 | |
| Tax Rate | 26.5% | 26.5% | |
| **Subtotal** | 0.1 | 0.4 | |
| Less: Tax Credits | - | - | |
| **Total Income Taxes** | **0.1** | **0.4** | E-09-04, Attachment 1 |

### 2.1.4 HOSSM RETURN ON CAPITAL

The calculation of the Return on Capital that forms part of the HOSSM revenue requirement is shown below in Table 5.

**Table 5 - HOSSM Return on Capital ($M)**

| | 2027 | 2028 | Reference |
|---|---|---|---|
| Debt Cost | 9.8 | 10.6 | |
| Return on Equity | 12.6 | 13.7 | |
| **Return on Capital** | **22.4** | **24.3** | F-02-03 |

## 2.2 HOSSM REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

### 2.2.1 2028 AND 2027 COMPARED TO 2016

The HOSSM revenue requirements for 2027 ($46.1M) and 2028 ($50.0M) are shown in Table 1 above. The proposed revenue requirements for 2027 and 2028 represent increases of 16% and 25%, respectively, compared to the OEB-approved 2016 amounts of approximately $6.2M and $10.1M. These increases are predominantly driven by rate

base growth (see Exhibit C-01-02). A more detailed breakdown of the drivers is provided in Table 6 below.

**Table 6 - Impact of Individual Components on HOSSM Revenue Requirement**

| Description | 2027 vs 2016 OEB-Approved ($M) | 2027 vs 2016 OEB-Approved (%) | 2028 vs. 2016 OEB-Approved ($M) | 2028 vs. 2016 OEB-Approved (%) |
|---|---|---|---|---|
| Rate Base Growth | 14.6 | 37% | 18.6 | 47% |
| Decrease in OM&A | (0.8) | (2%) | (0.5) | (1%) |
| Income Tax Changes | (3.7) | (9%) | (3.8) | (10%) |
| Lower Cost of Capital Parameters | (3.9) | (10%) | (4.2) | (11%) |
| **Impact on Revenue Requirement** | **6.2** | **16%** | **10.1** | **25%** |

# 2027 HOSSM REVENUE REQUIREMENT

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# 2028 HOSSM REVENUE REQUIREMENT

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# 2032 HOSSM REVENUE REQUIREMENT

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# TRANSMISSION EXTERNAL REVENUES

## 1.0 OVERVIEW

This exhibit describes Hydro One Transmission's external revenues received from sources other than transmission rates. External revenues are applied as an offset to Hydro One's revenue requirement (presented in Exhibit D-01-01). Table 1 below provides details regarding Hydro One Transmission's external revenues for the 2023-2032 period.

**Table 1 - Transmission External Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Secondary Land Use | 37.7 | 38.8 | 47.2 | 40.5 | 46.1 | 39.6 | 39.7 | 39.7 | 39.7 | 39.7 |
| Station Maintenance | 3.0 | 3.1 | 2.7 | 2.2 | 2.7 | 2.7 | 2.7 | 2.9 | 2.9 | 2.9 |
| Engineering & Construction | 1.0 | 1.8 | 0.4 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Other External Revenues | 9.2 | 9.7 | 16.2 | 10.3 | 13.8 | 11.7 | 11.3 | 9.6 | 9.5 | 9.5 |
| **Total** | **50.9** | **53.4** | **66.5** | **53.4** | **62.9** | **54.3** | **54.1** | **52.6** | **52.6** | **52.6** |

External revenues earned through the provision of services to third parties are forecast to be $54.3M in 2028, decreasing by $0.2M to $54.1M in 2029. Forecast external revenues further decrease by $1.5M to $52.6M in 2030 and then remain stable at $52.6M annually through 2032. The 2028–2032 forecast reflects continued revenues from secondary land use, station maintenance services, engineering and construction services, and other external revenue activities, as described in the sections below.

As further described in Exhibit G-01-03, section 2.7, Hydro One has variance accounts to track the difference between the actual external revenues and the revenues approved by the OEB in prior rate proceedings. The external revenues variance accounts help protect Hydro One's customers and keep them whole.

Hydro One's strategy is to prioritize core work while continuing to respond to external customer work requests where the utility has the available resources and assets to accommodate them. Costs associated with external work are described in Exhibit E-04-06. External work is costed on a cost-causality basis, consistent with internal work, using standard labour rates, equipment rates, material surcharges, and overhead rates. An appropriate margin is added to reflect, at a minimum, market-level pricing and ensure an overall benefit to transmission ratepayers. Further details on the cost of external work are provided in Exhibits C-09-01 to C-09-04.

## 2.0 DESCRIPTION OF TRANSMISSION EXTERNAL REVENUES

This section describes each external revenue component and discusses relevant trends for each.

### 2.1 SECONDARY LAND USE

Hydro One's Secondary Land Use (SLU) program generates revenue by permitting compatible uses on transmission corridors and other lands. Typical compatible use areas include parking lots, signboards, personal communication systems (PCS), municipal and private roadways, recreational parks and trails, agricultural areas, sewers, watermains and pipelines, other municipal infrastructure occupations, as well as public transit infrastructure and commuter lots.

SLU revenue generally falls into two categories. The first category is for revenues from agreements permitting compatible secondary uses on Hydro One owned lands, primarily on the corridor portions of transmission and distribution station lands, or on corridor lands acquired after 2003. Hydro One retains all revenue generated from these third-party secondary land use agreements.

The second category is the Provincial Secondary Land Use Program (PSLUP). Hydro One manages the PSLUP on behalf of the Ontario Government for transmission corridor lands that were transferred to the Province under the *Reliable Energy and Consumer Protection Act, 2002*, S.O. 2002, c. 1 (the "Act").

Pursuant to the Act: (i) all expiring SLU agreements were transferred to the Province of Ontario as of December 31, 2002; (ii) unexpired agreements that existed prior to the Act continue to be administered by Hydro One, with associated revenues retained by Hydro One until expiry; and (iii) upon expiry, these agreements and associated revenues transfer to the Province and become part of the PSLUP.

Hydro One and the Province of Ontario are parties to an agreement that governs administration of the PSLUP. Under this framework, Hydro One provides front-line delivery services on behalf of the Province, while PSLUP revenues from applicable agreements are shared between Hydro One and the Province. PSLUP revenues are generated through third-party agreements permitting secondary land uses on Province-owned transmission corridor lands.

PSLUP revenues comprise the majority of SLU program workload. Under the PSLUP, Hydro One receives proposals from third parties seeking to use transmission corridor lands for compatible purposes. These proposals undergo a technical and safety review by internal experts to determine use compatibility with the corridor. Proposals that meet Hydro One's technical and safety requirements and receive necessary approvals from Hydro One and the Province proceed to formal licensing agreements, which then generate associated revenues.

Table 2 below presents the SLU revenues for the 2023-2032 period.

**Table 2 - Secondary Land Use External Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Secondary Land Use | 37.7 | 38.8 | 47.2 | 40.5 | 46.1 | 39.6 | 39.7 | 39.7 | 39.7 | 39.7 |

Hydro One's 2028 Test Year forecast for SLU revenues is $39.6M, a decrease of $6.5M from the 2027 forecast of $46.1M. The forecast revenue decline beginning in 2028 is

primarily attributable to lower anticipated transaction activity. The forecast is informed by annual land appraisals for geographic sections of the province, market activity, and anticipated corridor utilization. The elevated revenues realized from 2025 to 2027 reflected unusually high levels of major third-party infrastructure projects, corridor co-location opportunities, and development-related transactions. These included higher-value licence agreements associated with major public transit infrastructure and related traction power facilities. Several of these agreements are one-time or short-term in nature and are expected to end. As a result, the forecast reflects fewer revenue-generating transactions relative to the elevated level of activity experienced from 2025 to 2027.

Although the volume of requests is expected to decline, the complexity and duration of negotiations continue to increase, requiring sustained resource levels to support stakeholder engagement, technical reviews, regulatory requirements, and transaction execution. SLU revenues are forecast to remain stable at approximately $39.7M annually from 2029 to 2032. The associated cost of sales treatment for SLU is addressed in Exhibit E-04-06.

## 2.2 STATION SERVICES

Revenues from external work in the Station Services segment include repairing and maintaining high-voltage electrical equipment (such as transformers, breakers, switches and protection systems), specialty machining services (including spindles and generator rotors), protective relay installation, testing, maintenance and calibration, coordinating services required to reconnect modified systems to the transmission network, as well as providing metering, commissioning and emergency response services.

These services leverage Hydro One's specialized technical workforce, field resources, facilities and operational expertise that are also used to support Hydro One's transmission system. The work is highly specialized in nature and is often performed on critical transmission, generation and distribution assets where specialized expertise, unique tooling, system knowledge and high-voltage operating experience are required.

Customers seek out these services because Hydro One maintains unique technical capabilities and experienced personnel able to perform work across a broad range of high-voltage equipment and operating environments, including transmission stations, generation facilities, industrial facilities and other utility systems. In many cases, the services provided are niche in nature and support equipment or operational requirements for which limited alternative service providers exist within Ontario. Work is performed pursuant to commercially negotiated agreements that reflect market-based pricing.

Hydro One's external Station Services work primarily supports Ontario's electricity sector, including transmission-connected generators, local distribution companies, transmitters and other electricity market participants. A significant portion of this work is associated with supporting key generation facilities, including Bruce Power and Ontario Power Generation, as well as original equipment manufacturers and other utilities operating critical electricity infrastructure. By providing these specialized services, Hydro One contributes to the reliable operation, maintenance and restoration of electricity assets that support customers and ratepayers across the province

Table 3 below presents the Station Maintenance revenues for the 2023-2032 period.

**Table 3 - Station Maintenance External Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Station Maintenance | 3.0 | 3.1 | 2.7 | 2.2 | 2.7 | 2.7 | 2.7 | 2.9 | 2.9 | 2.9 |

Hydro One’s 2028 Test Year forecast for Station Maintenance external revenues is $2.7M. The 2028 Test Year forecast is generally in line with the 2026 and 2027 forecast amounts and is lower than both 2023 actual revenues of $3.0M and the average annual revenues over the 2023–2027 rate period of approximately $2.8M. The forecast reflects station maintenance services scope adjustments as Hydro One continues to prioritize its internal work program requirements.

Witness: Scott Vicary; Julie Ricketts Daniel

## 2.3 ENGINEERING AND CONSTRUCTION

Hydro One's engineering and construction activities focus on work supporting Acronym Solutions Inc. (Acronym Solutions), formerly Hydro One Telecom Inc. (HOT), a wholly owned subsidiary of Hydro One. In particular, Hydro One supports Acronym Solutions customer requests for new interconnections with Hydro One's optical fibre infrastructure by providing design, quote, and build services related to Acronym Solutions work within Hydro One's transmission station property.

Table 4 below presents the Engineering and Construction external revenues for the 2023-2032 period.

**Table 4 - Engineering and Construction External Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Engineering & Construction | 1.0 | 1.8 | 0.4 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |

Hydro One's 2028 Test Year forecast for Engineering and Construction external revenues is $0.4M. The forecast is consistent with the 2025 and 2027 amounts and is below the 2023–2027 average annual revenues of approximately $0.8M, which reflects higher revenues in 2023 and 2024. The forecast reflects expected support for Acronym Solutions customer requests for new interconnections with Hydro One's optical fibre infrastructure.

## 2.4 OTHER

The Other category of external revenues includes revenues from: providing various capital and maintenance work to Hydro One's affiliates (as further described in Exhibit D-02-03); telecommunications services to Ontario Hydro successor companies, such as lease of fibre and shared network services; stations and grid operations support, including maintenance and operating service contracts; asset management services, such as shared use of transmission infrastructure and planning studies, including transmission CIA

and other special studies; customer shortfall payments (e.g. true-ups, temporary bypass); and other miscellaneous external revenues, including lump-sum or contract-based revenues. These include transfer price charges to Hydro One's affiliate companies.

Table 5 below presents the Other category of external revenues for the 2023-2032 period.

**Table 5 - Other External Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Other External Revenues | 9.2 | 9.7 | 16.2 | 10.3 | 13.8 | 11.7 | 11.3 | 9.6 | 9.5 | 9.5 |

Hydro One's 2028 Test Year forecast for Other External Revenues is $11.7M. This is $2.5M higher than 2023 actual revenues of $9.2M and $4.5M lower than 2025 actual revenues of $16.2M. The 2028 Test Year forecast is generally in line with the average annual revenues over the 2023–2027 rate period of approximately $11.8M. Other External Revenues are forecast to decrease to $11.3M in 2029 and then remain stable at approximately $9.5M to $9.6M annually from 2030 to 2032.

The higher forecast amounts in 2027 to 2029 are primarily driven by grid operating contracts; affiliate-related services, including Transmission Lines Maintenance and Vegetation Management for B2M LP, NRLP and CLLP; shared use of transmission infrastructure; and other recurring telecommunications and asset management services. The decrease from $11.7M in 2028 to $11.3M in 2029 is mainly attributable to a $0.4M reduction in Vegetation Management, partially offset by increases in grid operating contracts and affiliate-related transmission services. The further decrease to approximately $9.6M in 2030 primarily reflects the expected completion of B2M LP Transmission Lines Maintenance work, which reduces revenues by $1.2M, and a $0.8M reduction in Vegetation Management, largely associated with NRLP. Revenues remain stable through 2032 because modest growth in affiliate-related transmission services is largely offset by declining corporate cost allocations, while grid operating contracts, shared

transmission infrastructure, and other recurring telecommunications and asset management services remain broadly stable.

# CHAPTER 2 APPENDIX 2-H OTHER OPERATING REVENUE FOR TRANSMISSION (EXTERNAL REVENUES)

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# DISTRIBUTION EXTERNAL REVENUES

## 1.0 INTRODUCTION

This Exhibit details Hydro One Distribution's external revenues, which are earned through services provided to third parties and the joint use of Hydro One Distribution assets. These revenues offset Hydro One's Distribution revenue requirement, thereby reducing the revenue requirement recovered from customers. Table 1 provides an overview of Hydro One Distribution's external revenues over the 2023 to 2032 period.

**Table 1 - Distribution External Revenues ($M)[1]**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** |
| | **Actual** | **Actual** | **Actual** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** |
| Regulated Revenue | 36.7 | 39.5 | 46.0 | 40.5 | 41.2 | 43.8 | 44.5 | 45.3 | 46.2 | 47.1 |
| Unregulated Revenue | 4.7 | 15.9 | 15.7 | 4.4 | 4.5 | 4.6 | 4.7 | 4.8 | 4.9 | 4.9 |
| **Sub-Total External Revenue** | **41.4** | **55.4** | **61.7** | **44.9** | **45.7** | **48.4** | **49.2** | **50.0** | **51.1** | **52.1** |
| Standard Supply Service Charge | 4.4 | 4.4 | 4.5 | 4.4 | 4.4 | 4.5 | 4.5 | 4.5 | 4.7 | 4.8 |
| microFIT Revenue | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.7 | 0.4 | 0.3 |
| ST Local Transformation Charge | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.4 | 0.5 | 0.5 | 0.6 |
| **Total External Revenue and Other** | **46.7** | **60.8** | **67.3** | **50.4** | **51.3** | **54.1** | **55.0** | **55.7** | **56.7** | **57.8** |

External revenues are categorized as regulated and unregulated. Regulated revenues are based on OEB-approved specific service charges detailed in Exhibit L-04-01. For

[1] Rounded figures within tables may not sum precisely due to rounding.

unregulated work, Hydro One applies an appropriate margin above cost that, at a minimum, addresses the risk of non-payment by third parties.

The cost of external work is determined on a cost-causality basis. Estimates are prepared using the standard labour, equipment, material surcharge, and overhead rates applied to internal work. Further information on costing methodology is provided in Exhibit C-09-01.

This Exhibit also includes revenues received from the Standard Supply Service Charge, microFIT Revenue, and Sub-Transmission (ST) Local Transformation Charge as described below.

- **Standard Supply Service Charge:** The Supply Service Charge is an OEB-set administrative fee paid by customers who purchase electricity directly from their local utility. This charge is also deducted from Hydro One's Distribution revenue requirement.
- **microFIT Revenue:** The current OEB-approved province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator Service Classification is $5.00 per month. In accordance with Section 2.3.3 of Chapter 2 of the Filing Requirements, revenue from the microFIT charge is recorded as a revenue offset in Uniform System of Accounts (USoA) Account 4235 – Miscellaneous Service Revenue and is not included as part of the base distribution revenue requirement.
- **ST Local Transformation Charge:** Since 2023, Hydro One has offered a local transformation option for its ST customers. ST customers who choose to use Hydro One-owned local transformers will be subject to a fixed "local transformation charge", as described in Exhibit L-02-01. The revenue from this monthly local transformation charge will be recorded as a revenue offset in USoA Account 4220 – "Other Electric Revenue" and not be included as part of the base distribution revenue requirement.

Costs associated with the recognition of these external revenues are presented in Exhibit E-04-07.

## 2.0 DESCRIPTION OF DISTRIBUTION EXTERNAL REVENUES

This section describes each external revenue component and discusses relevant trends for each.

## 2.1 REGULATED EXTERNAL REVENUES

Regulated external revenues for the 2023-2032 planning period are set out in Table 2 below. The sources of these revenues and relevant variances in each are discussed below.

**Table 2 - Regulated Revenues ($M)[2]**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** |
| | **Actual** | **Actual** | **Actual** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** |
| Retail Service | 17.7 | 19.1 | 23.1 | 20.1 | 20.2 | 22.2 | 22.4 | 22.6 | 22.8 | 23.0 |
| Joint Use | 13.4 | 14.0 | 14.9 | 14.9 | 15.5 | 16.8 | 17.4 | 18.1 | 18.8 | 19.5 |
| Sentinel Lights | 2.9 | 2.8 | 2.6 | 2.3 | 2.2 | 2.1 | 2.0 | 1.9 | 1.9 | 1.9 |
| Other External Work | 2.2 | 3.4 | 5.0 | 2.9 | 3.0 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 |
| Distributor Generator Studies | 0.5 | 0.2 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Total** | **36.7** | **39.5** | **46.0** | **40.5** | **41.2** | **43.8** | **44.5** | **45.3** | **46.2** | **47.1** |

### 2.1.1 RETAIL SERVICE REVENUES

Table 3 below outlines the Retail Service revenues for the 2023-2032 period.

[2] Rounded figures within tables may not sum precisely due to rounding.

**Table 3 - Retail Service Regulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Retail Service | 17.7 | 19.1 | 23.1 | 20.1 | 20.2 | 22.2 | 22.4 | 22.6 | 22.8 | 23.0 |

As described in Exhibit L-04-01, Hydro One provides a range of customer administration services that generate retail service revenues. The increase in revenues between 2023 and 2025 primarily reflects the discontinuation of the Account Set Up fee waiver that had been introduced to encourage digital self-service adoption. The waiver was removed as part of an initiative to improve customer experience consistency across channels and reduce operational inefficiencies associated with channel switching and duplicate handling of customer requests. Retail service revenues are forecast to remain relatively stable over the bridge and forecast periods, reflecting steady-state customer administration activities, with modest growth driven by customer growth and normal business activity.

### 2.1.2 JOINT USE REVENUES

Table 4 below outlines the Joint Use revenues for the 2023-2032 period.

**Table 4 - Joint Use Regulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Joint Use | 13.4 | 14.0 | 14.9 | 14.9 | 15.5 | 16.8 | 17.4 | 18.1 | 18.8 | 19.5 |

Joint use revenues are generated from third parties that attach facilities on Hydro One Distribution poles. For this right, Hydro One charges an attachment fee per pole. As of 2026, there are approximately 560 joint use agreements in place with third-party joint users, such as reciprocal and non-reciprocal telecommunications companies, local distribution companies (LDCs), generators, and municipalities. Telecommunications attachments generate approximately 87% of joint use revenue.

Hydro One's Joint Use revenue forecast reflects continued increases in joint use attachments due to the *Building Broadband Faster Act* (BBFA).

### 2.1.3 SENTINEL LIGHT REVENUES

Table 5 below outlines the Sentinel Light revenues for the 2023-2032 period.

**Table 5 - Sentinel Light Regulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Sentinel Lights | 2.9 | 2.8 | 2.6 | 2.3 | 2.2 | 2.1 | 2.0 | 1.9 | 1.9 | 1.9 |

The sentinel light rental program is designed to provide rural customers with low-cost security lighting. The service is provided primarily to rural residential, farm, and cottage customers, for whom street lighting is not available. The decrease over the bridge and forecast period reflects the fact that service is now limited to customers already participating in the rental program. New lights are no longer installed, and existing lights are removed upon customer request, resulting in a gradual decline in the number of lights installed and associated revenue.

### 2.1.4 OTHER EXTERNAL WORK - REGULATED

Table 6 below outlines the External Work revenues for the 2023-2032 period.

**Table 6 - Other External Work Regulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Other External Work | 2.2 | 3.4 | 5.0 | 2.9 | 3.0 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 |

Other external work includes work performed by Hydro One on behalf of Bell Canada as a part of new connections. These are connections where the customer, property or parcel of land that is directly adjacent to or abuts onto the public road allowance where Hydro One Networks has facilities and equipment of the appropriate voltage and capacity, and the building can be connected without requiring an expansion to the primary distribution system ("lies along connection"). This work drove the increase in revenues in 2024 and 2025.

Other external work also includes work performed by Hydro One on assets owned by its joint use partners; corporate functions and service charges from Hydro One that are charged to Acronym Solutions Inc. (Acronym) and Hydro One Remote Communities Inc. (Remotes); and streetlight repairs for several Northern Ontario communities in accordance with Hydro One's Streetlight Maintenance Agreement where electrical contractors are not locally available.

Regulated external revenues received from Hydro One affiliates include $0.3M forecasted for work related to Remotes and $0.4M related to Acronym. This revenue is related to work performed by Hydro One Distribution, the costs for which have not been allocated to affiliates using the common cost allocation methodology described in Exhibit E-04-08.

Pursuant to section 2.4.3.2 of the Filing Requirements, Exhibit E-04-01, Attachment 1 details the costs paid between Hydro One and its affiliates.

### 2.1.5 DISTRIBUTOR GENERATOR STUDIES

Table 7 below outlines the Distributor Generator Studies revenues for the 2023-2032 period.

**Table 7 - Distributor Generator Studies Work Regulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Distributor Generator Studies | 0.5 | 0.2 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |

Hydro One earns revenue by completing Connection Impact Assessments (CIAs) in response to connection requests from generation proponents in Ontario.[3] Hydro One performs CIAs based on a customer request that includes the proposed size of the generator and where it will be located.

After the termination of the Feed-in Tariff (FIT) program in 2018, Distributed Energy Resources (DER) activity shifted to behind-the-meter (BTM) load displacement generators participating in the IESO's Industrial Conservation Initiative (ICI) program and the Ontario Net Metering program. This resulted in a consistently moderate number of small and mid-sized DER applications in the years 2023 to 2025.

Moving forward, these DER activities are expected to continue, and an additional increase in DER activity is expected as a result of the IESO's Long Term Procurement program under the Resource Adequacy Framework. The first phase of the Long Term Procurement (LT1) is now complete with projects coming into service between 2026-2028. Additional generation is expected to connect under the second phase of this Long Term Procurement program (LT2) to meet energy needs in 2030 and beyond. Most recently, in 2025, the Province of Ontario announced solar photovoltaic incentives targeting participants who are interested in BTM solar installations to displace their load. Based on these ongoing DER programs and considering the findings of the "Ontario's Distributed Energy

[3] CIAs are technical studies that determine the impact of connecting new generation facilities to the distribution system and ensure that the generator will comply with the technical requirements. The technical requirements that generators must meet to connect to Hydro One distribution system are outlined in the document entitled "Distributed Generation Technical Interconnection Requirements (TIR) for Generators Connecting to Hydro One's Distribution System." These TIR requirements exist to ensure public and employee safety, to protect the integrity of Hydro One's Distribution System, and to guarantee reliable and quality service.

Resources (DER) Potential Study" prepared for the IESO by Dunsky Energy + Climate Advisors, which forecasts an increase in DER activity in the Province, particularly from 2028 onward, Hydro One expects an increase in CIA applications across all categories of small, mid-sized and large DERs over the 2028 to 2032 planning period. [4]

## 2.2 UNREGULATED EXTERNAL REVENUES

Historical and forecast unregulated external revenues are set out in Table 8 below.

**Table 8 - Unregulated Revenues ($M)[5]**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Joint Use | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Other External Work | 4.6 | 4.5 | 15.3 | 4.4 | 4.4 | 4.6 | 4.6 | 4.7 | 4.8 | 4.9 |
| Storm Revenue | 0.0 | 11.3 | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **4.7** | **15.9** | **15.7** | **4.4** | **4.5** | **4.6** | **4.7** | **4.8** | **4.9** | **4.9** |

### 2.2.1 JOINT USE REVENUES - UNREGULATED

Table 9 outlines the Joint Use unregulated revenues for the 2023-2032 period.

**Table 9 - Joint Use Unregulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast[6] | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Joint Use | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

[4] Dunsky Energy + Climate Advisors, "Ontario's Distributed Energy Resources (DER) Potential Study" (28 September 2022), available online: https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/DER-Potential-Study

[5] Rounded figures within tables may not sum precisely due to rounding.

[6] Forecast revenues are $42,336 annually but appear as $0.0 due to rounding.

Hydro One also receives revenues for joint use services for which the OEB does not set rates. These services consist of under-density billing revenues for northwestern Ontario through annual fees levied upon two large companies that use dedicated, under density distribution lines operated and maintained by Hydro One Distribution. The load on these lines does not cover the annual maintenance costs. Accordingly, an annual fee is charged to recover these costs. Unregulated Joint Use revenue is forecast to remain constant at $42,336 annually, consistent with existing fee arrangements.

### 2.2.2 OTHER EXTERNAL WORK – UNREGULATED

Table 10 outlines the Other External Work unregulated revenues for the 2023-2032 period.

**Table 10 - Other External Work Unregulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Other External Work | 4.6 | 4.5 | 15.3 | 4.4 | 4.4 | 4.6 | 4.6 | 4.7 | 4.9 | 4.9 |

Other external work includes external training and unregulated revenues from Hydro One affiliates.

External training includes practical and classroom-based courses for line trades, power substation electricians, metering technicians, and electrical operators. Customers include Ontario utilities and contractors, with training provided to employees from a range of trades and technical disciplines.

Unregulated revenues from Hydro One affiliates include $1.5M in the forecast years for work related to Hydro One Remotes Communities Inc. This revenue is related to Hydro One Distribution work, the costs for which have not been allocated to affiliates using the common cost allocation methodology described in Exhibit E-04-08.

The increase in Other External Work revenue in 2025 reflects amounts recovered for the replacement of Bell-owned poles following the spring ice storm.

### 2.2.3 STORM REVENUES

Table 11 outlines the Storm unregulated revenues for the 2023-2032 period.

**Table 11 - Storm Unregulated Revenues ($M)**

| | Historical | | | | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** |
| | **Actual** | **Actual** | **Actual** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** |
| Storm Revenue | 0.0 | 11.3 | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

Storm revenues arise when Hydro One provides mutual assistance to utilities outside Ontario following major power outages. The $11.3M recorded in 2024 reflects deployments in response to Hurricane Helene and Hurricane Milton. Because these revenues depend on the occurrence of significant storms and Hydro One's ability to deploy resources to other jurisdictions, no storm revenues are forecast.

The following attachment is provided as part of this section:

- **Attachment 1** – Dx Chapter 2 Appendix 2-H: Other Operating Revenue for Distribution (External Revenues)

# CHAPTER 2 APPENDIX 2-H: OTHER OPERATING REVENUE FOR DISTRIBUTION (EXTERNAL REVENUES)

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# AFFILIATE SERVICES

## 1.0 INTRODUCTION

This Exhibit describes the range of services, products, resources and uses of assets that Hydro One Networks Inc. (Hydro One Networks) provides to and receives from its affiliates (Affiliate Services), as well as the manner in which the revenues received and costs incurred by Hydro One Networks in respect of Affiliate Services are accounted for in this Application.[1]

## 2.0 AFFILIATE SERVICE LEVEL AGREEMENTS

All Affiliate Services are provided or received by Hydro One Networks pursuant to affiliate service level agreements (Affiliate SLAs), as required under the OEB's *Affiliate Relationships Code for Electricity Distributors and Transmitters* (the ARC). Affiliate SLAs generally have one-year terms and are documented, approved and executed annually by senior executives or other staff with the relevant accountability and signing authority from each affiliate that is a party to the agreement.

Some Affiliate Services provided and received by Hydro One Networks under Affiliate SLAs are for shared corporate services, whereby centralized business operations are used to support multiple businesses within the Hydro One group of companies. The allocated costs to affiliates for the shared corporate services are determined by the common corporate cost allocation methodology described in Exhibit E-04-08.

Affiliate Services, other than the shared corporate services described above, (including utility operation and maintenance services, and telecommunication services) which are also provided and received by Hydro One Networks under Affiliate SLAs, are directly charged by the applicable service provider to the applicable service recipient. A portion of the revenues received by Hydro One Networks from providing Affiliate Services are accounted for as Other External Revenues in Exhibits D-02-01 and D-02-02 and are

[1] Including Transfer Pricing Charge further discussed in Exhibit C-03-01

applied as an offset to Hydro One Networks' Transmission and Distribution revenue requirements (as applicable) for the purposes of determining its Transmission and Distribution rates revenue requirements. The remainder of the costs incurred by affiliates are billed directly to the affiliates and are therefore not required to be recognized as External Revenue to the Distribution and Transmission businesses.

Section 3.0 below provides a summary of the shared and directly charged Affiliate Services that Hydro One Networks provides to its affiliates under Affiliate SLAs. Section 4.0 provides a summary of the shared and directly charged Affiliate Services that Hydro One Networks *receives* from its affiliates under Affiliate SLAs. Section 5.0 provides a summary of the key terms contained in Hydro One Networks' Affiliate SLAs. To provide context for this schedule, please refer to Hydro One Limited's corporate structure, which is depicted in Attachment 1 of Exhibit A-07-01.

## 3.0 AFFILIATE SERVICES PROVIDED BY HYDRO ONE NETWORKS

The tables below set out the Affiliate SLAs for Affiliate Services provided by Hydro One Networks to its affiliates in 2026 and which are expected to be in place for the 2027 bridge year and the 2028 test year, as well as subsequent years. As noted, some of the Affiliate Services provided by Hydro One Networks to its affiliates are shared corporate services subject to the common corporate cost allocation methodology, and some are directly charged by Hydro One Networks to its affiliates with the revenue received by Hydro One Networks applied as an offset to revenue requirement.

## 3.1 SHARED SERVICES PROVIDED BY HYDRO ONE NETWORKS

**Table 1 - Shared Corporate Services Provided by Hydro One Networks Inc.**

| AFFILIATE SERVICE PROVIDER | AFFILIATE SERVICE RECIPIENT(S) | AFFILIATE SERVICES |
|---|---|---|
| Hydro One Networks Inc. | Hydro One Limited<br><br>Hydro One Inc.<br><br>Hydro One Remote Communities Inc. (Remotes)<br><br>Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.)<br><br>B2M LP<br><br>Niagara Reinforcement LP<br><br>Hydro One Sault Ste. Marie LP (HOSSM)<br><br>Chatham x Lakeshore LP<br><br>Aux Energy Inc. | ***a) General Counsel Services*** – Professional legal advice and input (to the General Partners, in the case of the Limited Partnerships) and corporate secretariat and code of conduct services.<br><br>***b) Regulatory Services*** – services related to rates and revenue requirement applications and regulatory strategic advice regarding compliance with code and other regulatory instruments<br><br>***c) Financial Services*** – Financial information, business planning and decision support, budgeting and financial reporting as well as other financial services such as treasury/pension, taxation, financial systems and services, cost and inventory accounting, fixed asset and general accounting and audit-related services.<br><br>***d) Corporate Services*** – Facility management and real estate services, human resource services, labour relations, corporate communications, marketing and stakeholder relations, security, Indigenous relations, information management services, and enterprise architecture and IT operations.<br><br>***e) Telecommunications Services*** – Various telecommunications-related services, including field and engineering, logistics, corporate, construction, telecommunication and information technology services.<br><br>***f) Other Services*** – Customer services operations and information management.<br><br>***g) System Services*** – Use of core business systems such as SAP.<br><br>***h) Lease of computer equipment*** - lease of computer servers.<br><br>***i) Asset Management Services (for HOSSM Only)*** – Develop Asset Management strategy, policy, projects, programs, and processes; perform related technical, economic environmental and other specialized assessments as required to evaluate assets and system |

| | | |
|---|---|---|
| | | needs; prepare, submit and participate in HOSSM's rate application and related processes; monitor and maintain regulatory compliance with all applicable regulating bodies, and report non-compliance.<br><br>***j) Large Customer Accounts Services (for HOSSM Only)*** – Account Executive Services (including Report and Contract Reporting services) and Network Officer Management services. |

## 3.2 DIRECTLY CHARGED SERVICES PROVIDED BY HYDRO ONE NETWORKS

**Table 2 - Directly Charged Affiliate Services Provided by Hydro One Networks Inc.**

| AFFILIATE SERVICE PROVIDER | AFFILIATE SERVICE RECIPIENT(S) | AFFILIATE SERVICES |
|---|---|---|
| Hydro One Networks Inc. | Hydro One Remote Communities Inc. | ***Master Agreement for Utility Operation Services*** – Forestry services, training and development services, metering services, distribution lines services and work management services, safety services, fleet services, environmental services, engineering services, flight safety services, distribution planning technical services, joint use services, disability management & health services, winter road transport, logistic and stock keeping services, generation station services, facility services, helicopter services, customer communication services (including printing and mailing services) |
| Hydro One Networks Inc. | Hydro One Remote Communities Inc. | ***Supply Chain Services*** – Management and procurement, vendor management, process development, data management, and investment recovery. |
| Hydro One Networks Inc. | Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.) | ***Supply Chain Services*** – Management and procurement, vendor management, process development, data management, and investment recovery. |
| Hydro One Networks Inc. | Aux Energy Inc. | ***Supply Chain Services –*** Management and procurement, vendor management, process development, data management, and investment recovery |
| Hydro One Networks Inc. | Hydro One Sault Ste. Marie LP (HOSSM) | ***Master Agreement*** – Engineering services, environmental services, facilities and real estate services, forestry services, joint use services, settlement services, supply chain services, transmission, construction and maintenance services. |

| | | |
|---|---|---|
| Hydro One Networks Inc. | Hydro One Sault Ste. Marie LP (HOSSM) | ***Network Operations Services*** – Monitoring, control and operation of the transmission system, emergency response to transmission system events, outage processing, crew dispatching, record maintenance, power system IT support. |
| Hydro One Networks Inc. | B2M LP | ***a) Operations Services*** – all services required in order to operate the transmission line, including all operating, maintenance, repair and refurbishment matters.<br><br>***b) Management Services*** – Services to assist with the performance of B2M GP Inc.'s management activities. |
| Hydro One Networks Inc. | Niagara Reinforcement LP | ***a) Operations Services*** – all services required in order to operate the transmission line, including all operating, maintenance, repair and refurbishment matters.<br><br>***b) Management Services –*** Services to assist with the performance of Hydro One Indigenous Partnerships GP Inc.'s management activities. |
| Hydro One Networks Inc. | Chatham x Lakeshore LP | ***a) Operations Services –*** services required in order to operate the transmission line, including without limitation, all operating, maintenance, repair and refurbishment matters.<br><br>***b) Management Services*** – activities that are required in connection with the management of the transmission business of the limited partnership. |
| Hydro One Networks Inc. | Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.) | ***Microwave Tower Lease Agreement*** – (a) leasing available towers (no longer being used by Hydro One Networks Inc.) to Acronym Solutions Inc.; (b) leasing space to Acronym Solutions Inc. on certain microwave towers still being used by HONI (space only towers); and (c) allowing Acronym Solutions Inc. to lease space on the available towers and to lease the leased space to third parties for the purpose of attaching antennae and other wireless telecommunication equipment and devices on such towers. |
| Hydro One Networks Inc. | Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.) | ***Dark Fibre IRU Agreement*** – Grant by Hydro One Networks Inc. to Acronym Solutions Inc., on an indefeasible right of use basis, certain dark optical fibre that is excess to Hydro One Networks Inc.'s teleprotection, control and communication needs. |
| Hydro One Networks Inc. | Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.) | ***Telecom Fibre Lease and Maintenance Agreement*** – Lease of dark optical fibre that is excess to Hydro One Networks Inc.'s teleprotection, control and communication needs from Hydro One Networks Inc. to Acronym Solutions Inc. |

## 4.0 AFFILIATE SERVICES RECEIVED BY HYDRO ONE NETWORKS

The tables below set out the Affiliate SLAs for Affiliate Services received by Hydro One Networks from its affiliates in 2026 and which are expected to be in place for the 2027 bridge year and the 2028 test year, as well as subsequent years. As noted, some of the Affiliate Services received by Hydro One Networks from its affiliates are shared corporate services subject to the common corporate cost allocation methodology, and some are directly charged by affiliates to Hydro One Networks with the applicable costs incurred by Hydro One Networks accounted for as part of the supporting costs for the application.

## 4.1 SHARED CORPORATE SERVICES RECEIVED BY HYDRO ONE NETWORKS

**Table 3 - Shared Corporate Services Received by Hydro One Networks Inc.**

| AFFILIATE SERVICE PROVIDER | AFFILIATE SERVICE RECIPIENT(S) | AFFILIATE SERVICES |
|---|---|---|
| Hydro One Limited | Hydro One Inc.<br><br>Hydro One Networks Inc.<br><br>Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.)<br><br>Aux Energy Inc. | ***a) General Counsel*** – Professional legal advice and input services.<br><br>***b) President and CEO Services*** – Strategic direction and management in an attempt to ensure that the Services Recipient's corporate goals are achieved.<br><br>***c) Chief Financial and Regulatory Officer Services*** – Strategic direction and management related to the development of regulatory instruments (licences) to ensure that the Services Recipient's corporate financial goals are achieved. Strategic approval with respect to investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting will also be provided as required.<br><br>***d) EVP, Digital and Technology Services -*** The Services Provider shall provide the Services Recipient with strategic direction and management to ensure that the Services Recipient's information systems, applications, infrastructure, network and security goals are achieved.<br><br>***e) EVP, Safety, Operations & Customer Experience Services -*** strategic direction and management in order to drive operational, health and safety |

| | | |
|---|---|---|
| | | excellence across distribution, forestry, LDC integrations, stations, reliability and maintenance functions, as well as customer and system operations.<br><br>***f) Chief Operating Officer Services -*** strategic direction and management related to operations, customer experience, capital portfolio delivery, safety and asset management, as well as strategy, energy transition and corporate development.<br><br>***g) EVP, Head of Human Resources Services -*** strategic direction and management related to Hydro One's human resources and labour relations.<br><br>***h) Corporate Affairs Services -*** strategic direction and management related to Hydro One's communications, marketing, community investment, research and insights, as well as policy and partnerships, community, stakeholder and government relations. |

| AFFILIATE SERVICE PROVIDER | AFFILIATE SERVICE RECIPIENT(S) | AFFILIATE SERVICES |
|---|---|---|
| Hydro One Inc. | Hydro One Limited<br><br>Hydro One Networks Inc.<br><br>Hydro One Remote Communities Inc.<br><br>Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.)<br><br>Hydro One Sault Ste. Marie LP (HOSSM)<br><br>B2M LP<br><br>Niagara Reinforcement LP<br><br>Chatham x Lakeshore LP | ***a) Administrative, Corporate Secretary and Code of Conduct Services*** - Hydro One's General Counsel, Corporate Secretary and Chief Ethics Officer may incur costs and expenses for goods or services to be used solely by a Services Recipient by paying for said goods and services using their corporate charge card that is under the Services Provider's name. In such cases, the Services Recipient shall reimburse the Services Provider for said costs and expenses. Services include corporate secretary and code of conduct services which will include, but shall not be limited to, advice concerning corporate structure and governance, guidance on business ethics and support regarding business code of conduct matters.<br><br>***b) President and CEO/Chair Office Services -*** support services relating to the strategic direction and management provided by the President and CEO and Chair in an attempt to ensure that the Services Recipient's corporate goals are achieved.<br><br>***c) Ombudsman Services -*** facilitate the resolution of complaints by customers of the Services Recipient that remain unresolved after having been processed through Hydro One's complaints handling process.<br><br>***d) Financial Services -*** services relating to the review of policies and procedures, treasury operations, pension, financial control and reporting will also be provided by the Services Provider to the Services Recipient as required by the Services Recipient.<br><br>***e) Strategy and Corporate Development Services -*** strategic direction regarding Hydro One's corporate strategy, including: (i) identifying, evaluating and executing opportunities to grow Hydro One's business through new ventures or innovation (either organically, partnerships or investments), help the Services Recipient create and foster a culture of innovation within its organization, and (ii) evaluating mergers and acquisitions opportunities; and support enterprise decisions with respect to capital allocations, capital structure, risk/return analysis.<br><br>***f) Investor Relations Services -*** external messaging and communications services in respect of Hydro One Limited's shareholders and the various Canadian and U.S. equity research analysts. |

## 4.2 DIRECTLY CHARGED SERVICES RECEIVED BY HYDRO ONE NETWORKS

**Table 4 - Directly Charged Affiliate Services Received by Hydro One Networks Inc.**

| AFFILIATE SERVICE PROVIDER | AFFILIATE SERVICE RECIPIENT(S) | AFFILIATE SERVICES |
|---|---|---|
| Acronym Solutions Inc. (formerly, Hydro One Telecom Inc.) | Hydro One Networks Inc. | ***Telecommunication Management Services*** – Monitoring of power system tele-protection, including analogue and digital microwave, PLC, fibre optic, radio and other systems; monitoring, management and operation of power system and business system telecom services; and providing alarm-based services, coordinated network management services, systems analysis services and carrier/vendor management services on behalf of both power system and business system telecommunications. |
| Hydro One Remote Communities Inc. | Hydro One Networks Inc. | ***Metering and Lines Services*** – Metering/technician work, lines work, training, flight services, diesel maintenance and stations support. |

## 5.0 KEY TERMS OF AFFILIATE SLAs

Hydro One Networks' Affiliate SLAs are compliant with the ARC. Where Hydro One Networks provides or receives Affiliate Services, it does so in accordance with an Affiliate SLA. Each Affiliate SLA includes descriptions of the relevant Affiliate Services (which have been summarized in the tables above), the applicable pricing or cost allocation mechanisms, confidentiality provisions, the apportionment of risks and the applicable dispute resolution process, as further described below. Hydro One Networks also ensures that confidential information is appropriately protected from and/or by its affiliates. As noted, Affiliate SLAs generally have one-year terms and are documented, approved and executed annually by senior executives or other staff with the relevant accountability and signing authority from each affiliate that is a party to the agreement.

## 5.1 PRICING AND COST ALLOCATION MECHANISMS

Where Hydro One Networks provides Affiliate Services (that are not shared corporate services) to an affiliate, if a reasonably competitive market exists for the Affiliate Services, Hydro One Networks charges no less than the greater of the market price and its fully allocated cost to provide such Affiliate Services, and if a reasonably competitive market does not exist for the Affiliate Services, Hydro One Networks charges no less than its fully-allocated cost to provide the Affiliate Services. The applicable pricing is specified in the relevant Affiliate SLA, and such charges are directly billed by Hydro One Networks to its affiliates thereunder.

Where Hydro One Networks receives Affiliate Services (that are not shared corporate services) from an affiliate, if a reasonably competitive market exists for the Affiliate Services, Hydro One Networks pays no more than the market price (determined through a competitive bidding process, benchmarking or other evidence as applicable) for such Affiliate Services, and if a reasonably competitive market does not exist for the Affiliate Services, Hydro One Networks pays no more than the affiliate's fully-allocated cost to provide the Affiliate Services. The applicable pricing is specified in the relevant Affiliate SLA, and Hydro One Networks pays such amounts in accordance with bills it receives directly from its affiliates thereunder.

For shared corporate services, as defined in the ARC, fully allocated cost-based pricing is applied regardless of whether or not there is a competitive market for those Affiliate Services. Rather than using transfer pricing to directly charge these amounts as between affiliates, Hydro One uses a common corporate cost allocation methodology, described in Exhibit E-04-08, to allocate such costs among Hydro One Networks and its affiliates based on the proportion of each shared Affiliate Service used or the benefit derived by each entity.

## 5.2 OTHER KEY TERMS

The Affiliate SLAs for shared corporate services contain appropriate confidentiality provisions that generally restrict access to information received by either party in

furtherance of the Affiliate SLAs (collectively, Confidential Information) and require each party to protect the confidentiality of the other party's confidential information, which includes information relating to consumers, smart sub-metering providers, wholesalers, retailers, or generators. The agreements also prescribe security safeguards to be adhered to by the party receiving such confidential information.

The Affiliate SLAs also allocate risks, including through reciprocal indemnification clauses wherein each party agrees to indemnify the other against damages attributable to the indemnifying party's performance and/or non-performance of its obligations under the Affiliate SLAs. These clauses contain exclusions of liability for certain categories of damages. As well, there are provisions that deal with deficiencies in the services provided and inaccuracies in fees payable.

To address any potential dispute arising between the parties to an Affiliate SLA in connection with the interpretation, performance, construction or implementation of the Affiliate SLA, which cannot be resolved by a director or manager from each party, a dispute resolution mechanism is included in the Affiliate SLA providing that any such dispute shall be escalated first to a director-level employee of each party and if resolution is not achieved at this level, then the dispute shall subsequently be escalated to the President of the ultimate parent of the Hydro One entities (i.e. Hydro One Limited).

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# HYDRO ONE LOAD FORECAST – KEY ECONOMIC AND DEMOGRAPHIC ASSUMPTIONS

## 1.0 INTRODUCTION

This Exhibit discusses the key economic and demographic assumptions that are common to both the Hydro One Transmission (including HOSSM) and Distribution load forecasts. The load forecasts in support of this Application are current as of April 2026 and were prepared using the forecast information available at that time.

The methodology that Hydro One has used to prepare the load forecasts, which is described in greater detail in Exhibits D-04-01 (Transmission Load Forecast) and D-05-01 (Distribution Load Forecast), draws on both end use and econometric approaches to understand how electricity demand is expected to evolve as the economy, technology and consumer behaviour change over time. The end use considerations reflect how electricity is expected to be used, including related government policies and mandates, and are used to inform and refine forecasts for these evolving dynamics. The econometric approach involves a macro-level consideration of statistical relationships between electricity consumption and changing economic and demographic variables over time. The results of these approaches are also informed by customer surveys, industry tracking, and relevant government information. Together, the end use and econometric approaches provide a robust and historically proven load forecasting methodology.

The economic and demographic assumptions and projections discussed in this Exhibit are used as inputs in preparing the Transmission load forecast, presented in Exhibit D-04-01, as well as the Distribution load forecast presented in Exhibit D-05-01.[1] In turn, those load forecasts are used for purposes of calculating Transmission and Distribution rates, as described in Exhibit H in respect of Transmission rates, and Exhibit L in respect of Distribution rates.

[1] "Load forecast" refers to peak demand and energy forecasts, as well as the forecast of number of customers in the case of Distribution.

## 2.0 KEY ASSUMPTIONS FOR THE DISTRIBUTION AND TRANSMISSION LOAD FORECASTS

The key inputs used in developing the load forecasts are Ontario GDP by sector, provincial demographics, economic indicators by sector, as well as energy prices, taking into account changing dynamics over time.[2] These remain the key drivers of electricity demand used to develop the load forecasts. The forecasts for these inputs are based on the most recent information available at the time the load forecasts were developed in April 2026. The detailed sources of information for these economic and demographic inputs, as well as discussions of how these inputs contribute to developing the load forecasts, are provided in Appendices A to C of Exhibits D-04-01 and D-05-01, for Transmission and Distribution, respectively.

### 2.1 PROVINCIAL GDP FORECAST

The provincial GDP is a key driver for the load forecast. During the last four years, the industrial sector continued to experience growth along with the world economy. This growth was not experienced broadly across all industries. For example, demand for Manufacturing, and Forestry and Logging products experienced an overall decline during the past four years.

Ontario GDP grew by 4.4% in 2022, 2.4% in 2023, 1.6% in 2024, and is expected to have grown by only 1.2% in 2025 due to tariffs.[3] Based on the April 2026 consensus forecast, which is an average of the forecasts produced by major banks and forecasting houses as defined in Appendix A of this Exhibit, Ontario GDP is expected to grow by 1.0% in 2026, 1.9% in 2027, and by an average of 2.0% per year over the years 2028 to 2032.

All forecasts presented in this Exhibit are based on information available as of April 2026 so that the forecasts account for the continuation of returning to normal levels of immigration and inflation in the short run after high immigration and inflation over the 2022 to mid-2025 period. Moreover, the forecast assumes positive economic impact over the

[2] Energy prices are sourced from the Canada Energy Regulator (CER).
[3] All 2025 data points will not be available on a final basis until the end of 2026.

long-term resulting from broad-based investment activities and population growth. Appendix A of this Exhibit provides the details of the consensus forecast for Ontario GDP along with the sources of the forecast. The sources for all other economic/demographic variables are provided in Appendices A and B of Exhibits D-04-01 and D-05-01, along with the forecasting models where they are used. The data discussed in this Exhibit are presented in Exhibit D-03-01-01.

## 2.2 PROVINCIAL POPULATION FORECAST

The Ontario population grew by 2.1% in 2022, 3.1% in 2023, 3.3% in 2024, and 0.7% in 2025. The forecast indicates that the Ontario population is expected to decline by 0.3% in 2026 and 0.1% in 2027 and then grow by an average rate of 0.9% over the years 2028 to 2032 based on the consensus forecast in line with its long-term historical average following higher than normal immigration targets over the 2022 to mid-2025 period and lower than normal immigration targets from mid-2025 to 2027. Population growth contributes positively to the load forecast.

## 2.3 PROVINCIAL HOUSING FORECAST

Helped by overall population growth, housing demand in Ontario continued to grow over the last four years. Housing starts statistics showed 96,100 new houses in 2022, 89,300 in 2023, and 74,600 in 2024, with 65,200 expected in 2025. The consensus forecast calls for 63,800 housing starts in 2026, 62,700 in 2027, and an average of 79,400 per year between the years 2028 and 2032, reflecting a return to long-term historical trend. Appendix A of this Exhibit provides the details of the consensus forecast for Ontario housing starts.

## 2.4 COMMERCIAL FLOOR SPACE FORECAST

Due to continued economic growth, on average, the pace of commercial construction activities was moderate over recent years. Commercial floor space grew by 2.4% in 2022, declined by 0.2% in 2023, increased by 1.2% in 2024, and is expected to decline by 0.8% in 2025. The forecast calls for 0.7% growth in 2026 and 2027 and an average of 0.7%

growth per year between 2028 and 2032. The forecast for commercial floor space additions is an important contributor to the commercial sector load forecast.

## 2.5 INDUSTRIAL PRODUCTION FORECAST

During the last four years, the industrial sector continued to grow but the growth was not broad-based. As previously discussed, Manufacturing, and Forestry and Logging experienced a decline during the past four years. Overall, however, industrial GDP grew by 5.0% in 2022, 1.5% in 2023, 2.3% in 2024, and is expected to grow by only 1.4% in 2025 due to tariffs. The consensus forecast calls for growth of 1.2% in 2026, 2.3% in 2027, and an average annual growth rate of 2.0% between 2028 and 2032. The industrial production forecast is an important contributor to the industrial sector load forecast, but it is also prone to economic cycles.

# APPENDIX A - CONSENSUS FORECAST[4]

**Survey of Ontario GDP Forecast (annual growth rate in %)**

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|
| Conference Board (Mar 2026) | 1.6 | 1.1 | 0.8 | 2.5 | 2.5 | 2.5 | | | |
| C4SE (Mar 2026) | 1.6 | 1.4 | 0.9 | 1.9 | 1.9 | 2.1 | 1.8 | 1.9 | 1.8 |
| CIBC (Oct 2025) | 1.2 | 1 | 1.3 | 2.1 | | | | | |
| BMO (Apr 2026) | 1.6 | 1.4 | 1.2 | 2.3 | | | | | |
| RBC (Mar 2026) | 1.6 | 1.2 | 0.9 | 1.3 | | | | | |
| Scotia (Jan 2026) | 1.6 | 1.3 | 1.2 | 1.7 | | | | | |
| TD (Mar 2026) | 1.4 | 1.4 | 0.9 | 1.8 | | | | | |
| Desjardins (Feb 2026) | 1.6 | 1.3 | 1.1 | 1.9 | | | | | |
| Central 1 (Dec 2025) | 1.6 | 0.8 | 0.9 | 1.7 | | | | | |
| National Bank (Mar 2026) | 1.6 | 1.2 | 0.6 | 1.4 | | | | | |
| **Average** | **1.5** | **1.2** | **1.0** | **1.9** | **2.2** | **2.3** | **1.8** | **1.9** | **1.8** |

**Survey of Ontario Housing Starts Forecast (in 000's)**

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|
| Conference Board (Mar 2026) | 74.6 | 65.4 | 66.3 | 70.1 | 78.0 | 86.4 | | | |
| C4SE (Mar 2026) | 74.6 | 65.4 | 61.6 | 65.1 | 71.4 | 77.0 | 79.9 | 80.9 | 79.8 |
| BMO (Apr 2026) | 74.6 | 65.3 | 62 | 59 | | | | | |
| RBC (Mar 2026) | 74.6 | 65.4 | 60.3 | 49.8 | | | | | |
| Scotia (Jan 2026) | 74.6 | 63 | 67 | 73 | | | | | |
| TD (Mar 2026) | 74.6 | 65.2 | 61.5 | 59.4 | | | | | |
| Desjardins (Feb 2026) | 74.6 | 71.3 | 73.8 | | | | | | |
| Central 1 (Dec 2025) | 74.6 | 61 | 62 | 70 | | | | | |
| National Bank (Mar 2026) | 74.6 | 64.9 | 60 | 55 | | | | | |
| **Average** | **74.6** | **65.2** | **63.8** | **62.7** | **74.7** | **81.7** | **79.9** | **80.9** | **79.8** |

**Forecast updated on April 11, 2026**

[4] Forecasts for the other variables, such as population, commercial floor space and industrial production, are based on the average of the Signal49 Research (formerly the Conference Board of Canada), and Stokes Economics (formerly Centre for Spatial Economics, or C4SE) projections, as these variables are less commonly forecasted than GDP and Housing Starts.

## APPENDIX B - ASSUMPTIONS UNDERPINNING HIGH AND LOW SCENARIOS

Assumptions underpinning high and low load forecast scenarios noted in B-03-01 are presented below.

**High scenario:** In this case, economy is growing faster than the reference scenario on a broad basis. For example, GDP and housing starts are growing faster than the reference scenario by 0.5% per year, as presented in the following table.

**Table A1 - Forecast for GDP and Housing Starts for High Scenario**

| | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|
| GDP Growth Rate (%) | 1.5 | 2.4 | 2.7 | 2.8 | 2.3 | 2.4 | 2.3 |
| Housing Starts (1,000) | 64.2 | 63.3 | 75.7 | 83.2 | 81.8 | 83.3 | 82.6 |

In addition, it is assumed that electrification adoption rate is growing 0.5% per year faster compared to the reference scenario. This applies to EV, electric space and water heating, and electrification of public transit and industry.

**Low Scenario:** In contrast, in the low scenario, economy is growing slower compared to the reference scenario on a broad basis. For example, GDP and housing starts are growing slower by 0.5% per year, as presented in the following table.

**Table A2 - Forecast for GDP and Housing Starts for Low Scenario**

| | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|
| GDP Growth Rate (%) | 0.5 | 1.4 | 1.7 | 1.8 | 1.3 | 1.4 | 1.3 |
| Housing Starts (1,000) | 63.5 | 62.0 | 73.6 | 80.1 | 78.0 | 78.6 | 77.1 |

In addition, it is assumed that electrification adoption rate increases slower compared to the reference scenario by 0.5% per year. This includes EV, electric space and water heating, and electrification of public transit and industry.

# DATA FOR HYDRO ONE LOAD FORECAST

This attachment has been filed separately in MS Excel format

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# TRANSMISSION LOAD FORECAST AND METHODOLOGY

## 1.0 INTRODUCTION

This Exhibit discusses Hydro One's Transmission load forecast and the related methodology.

The key load forecast supporting Hydro One's Transmission application is the hourly demand load forecast by customer delivery point. This forecast is used to prepare the charge determinant forecast for the following rate categories: Network Pool, Line Connection Pool, and Transformation Connection Pool. The load forecast in support of this Application was prepared in April 2026 using the available economic and forecast information.

Hydro One Transmission's forecasts of the average 12-month peak load for 2028 to 2032 for Ontario peak demand and for the three transmission rate categories are shown in Table 1a. Consistent with actual load patterns during the past five years, Hydro One's forecast of the Network peak marginally exceeds Ontario coincident-peak. HOSSM's Transmission forecast for 2027 to 2032 is shown in Table 1b.[1] The impacts of Conservation and Demand Management (CDM) and embedded generation are included in the forecasts shown in Tables 1a and 1b. Hydro One worked with the Independent Electricity System Operator (IESO) and used their latest CDM assumptions in preparing the load forecast in this Application, as detailed in Section 3.0 below.

[1] For HOSSM, the forecast for each charge determinant peak grows at the same rate as the corresponding Hydro One Transmission peak, as was the case during the historical period.

**Table 1a - Hydro One's 2028-2032 Load Forecast**

| (12-Month Average Peak in MW) | | | | |
|---|---|---|---|---|
| | Hydro One Rate Categories (Charge Determinants) | | | |
| | Ontario Demand | Network | Line Connection | Transformation Connection |
| 2028 | 20,800 | 20,975 | 20,666 | 17,153 |
| 2029 | 20,970 | 21,145 | 20,828 | 17,288 |
| 2030 | 21,251 | 21,429 | 21,098 | 17,512 |
| 2031 | 21,586 | 21,766 | 21,414 | 17,774 |
| 2032 | 21,949 | 22,133 | 21,756 | 18,058 |

**Table 1b - HOSSM's 2027-2032 Load Forecast**

| (12-Month Average Peak in MW) | | | | |
|---|---|---|---|---|
| | Hydro One Rate Categories (Charge Determinants) | | | |
| | Ontario Demand | Network | Line Connection | Transformation Connection |
| 2027 | 20,658 | 256 | 225 | 46 |
| 2028 | 20,800 | 258 | 226 | 46 |
| 2029 | 20,970 | 260 | 228 | 46 |
| 2030 | 21,251 | 263 | 231 | 47 |
| 2031 | 21,586 | 267 | 234 | 47 |
| 2032 | 21,949 | 272 | 238 | 48 |

## 2.0 SUMMARY OF HYDRO ONE'S LOAD FORECAST METHODOLOGY AND ASSUMPTIONS

Hydro One uses a number of methods, such as econometric and end-use approaches, customer forecast surveys and hourly load shape analyses to produce the forecasts required for its transmission business. A high-level overview of Hydro One's load forecasting methodology, including how the end-use and econometric approaches are used together, is provided in Exhibit D-03-01. This is the same load forecast methodology used and approved by the OEB in previous Hydro One rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110), with a refined end-use analysis to account for current and available information. All forecasts presented in this Exhibit are weather-normalized, meaning that abnormal weather effects are removed from the base year (2025) for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years. Hydro One Transmission continues to believe that this methodology is appropriate for the reasons specified below.

The transmission forecast is internally consistent such that the sum of all Hydro One customer delivery point forecasts adds up to the total for the entire customer base served by Hydro One Transmission's system. Hydro One Transmission's forecasting methodology comprises a combination of elements that include consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and the load impact of CDM including efficiency improvements and codes and standards.

Exhibit D-03-01 discusses in detail the various economic inputs taken into consideration when applying the methodology for deriving the load forecasts. Economic inputs are based on analyses prepared by major economic institutions in the country, such as all major banks, Signal49 Research (formerly The Conference Board of Canada), and Stokes Economics (formerly Centre for Spatial Economics, or C4SE for short). Specific customer development is based on forecast survey results from major customers. Inputs from these entities form the economic database (referred to henceforth as the economic forecast)

that is used to establish Hydro One Transmission's load forecast. The forecasts presented in this Exhibit are consistent with the economic assumptions used in the investment planning process as described in SPF 1.7.

## 3.0 KEY ASSUMPTIONS THAT INFLUENCE HYDRO ONE TRANSMISSION'S LOAD FORECASTS

The elements of the forecasting process used by Hydro One are based on knowledge of how the major economic drivers that affect electricity demand are likely to evolve over the forecast period of 2026 to 2032. Consequently, for the purpose of this Application, the focus is on the forecast period, and the load forecast will reflect those impacts that are likely to have a major effect in this respect. The key assumptions used in the analysis are summarized in Figure 1.

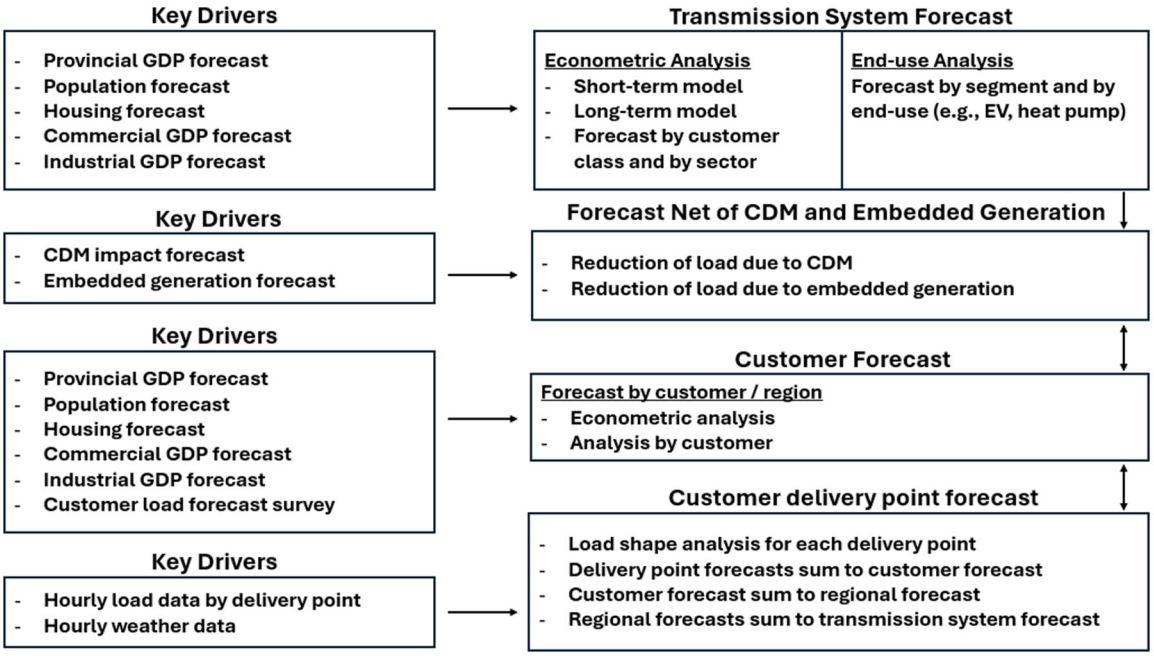


**Figure 1: Key Assumptions Used in the Forecast**

Key information used in the analysis includes Ontario GDP, provincial demographics, industrial production and commercial floor space forecasts. Also taken into consideration are the provincial CDM plans and embedded generation, which have a direct impact on

Hydro One Transmission system's energy demands. The load forecast also takes into account historical actual load and trends up to the end of 2025. The economic and demographic forecasts used to develop transmission load forecasts are further discussed in Exhibit D-03-01. The actual load is presented in Exhibit D-04-01-01.

## 3.1 CONSERVATION AND DEMAND MANAGEMENT FORECAST

Hydro One collaborated with the IESO to obtain a province-wide conservation forecast, which forms the basis for incorporating CDM impacts into the load forecast.

Hydro One adopted two CDM categories, consistent with the IESO's framework: (i) energy efficiency programs; and (ii) codes and standards.

The latest information provided by the IESO in the first quarter of 2026 is aligned with the IESO's most recent Annual Planning Outlook (APO). The methodology used by Hydro One to derive the CDM impacts for each of the three charge determinants is described in Sections 5.0 and 6.0 of this Exhibit.

Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2032.

**Table 2 - Load Impact of CDM on Ontario Demand (MW)**

| Year | Cumulative CDM Impact on Peak Demand * | Cumulative CDM Impact on 12-month Average Peak Demand ** |
|---|---|---|
| 2006 | 289 | 209 |
| 2007 | 778 | 561 |
| 2008 | 893 | 644 |
| 2009 | 997 | 720 |
| 2010 | 1,167 | 842 |
| 2011 | 1,318 | 971 |
| 2012 | 1,470 | 1,091 |
| 2013 | 1,621 | 1,221 |
| 2014 | 1,820 | 1,360 |
| 2015 | 1,942 | 1,433 |
| 2016 | 2,167 | 1,646 |
| 2017 | 2,099 | 1,587 |
| 2018 | 2,391 | 1,853 |
| 2019 | 2,639 | 2,055 |
| 2020 | 2,648 | 2,073 |
| 2021 | 2,935 | 2,361 |
| 2022 | 3,006 | 2,474 |
| 2023 | 3,166 | 2,645 |
| 2024 | 3,270 | 2,742 |
| 2025 | 3,479 | 2,966 |
| 2026 | 3,683 | 3,169 |
| 2027 | 3,718 | 3,242 |
| 2028 | 3,864 | 3,370 |
| 2029 | 3,994 | 3,483 |
| 2030 | 4,115 | 3,588 |
| 2031 | 4,191 | 3,655 |
| 2032 | 4,239 | 3,697 |

** The figures represent the load impact of CDM on annual peaks.*
*** The figures represent the load impact of CDM on monthly peak, averaged over 12 months in the year.*

## 3.2 EMBEDDED GENERATION FORECAST

In relation to Ontario demand, a total of 673 MW of embedded generation was assumed to be in place in 2024 and 2025, with an additional 83 MW in 2026, followed by an increase of 3 MW in 2027, and an average reduction of 45 MW per year over the 2028 to 2032 period due to the expiry of certain embedded generation contracts. The figures represent 12-month average peak and are based on information provided by the IESO, which reflects renewable energy projects in this regard.

# 4.0 LOAD FORECASTING METHODOLOGY

Hydro One Transmission's system load forecast is developed by correcting the base year (2025) for abnormal weather conditions, as explained in Section 4.2, and applying forecast growth rates to the normalized base year value. The load impacts of CDM and embedded generation are added back to the historical values during the modelling process (see Figure 2 below).

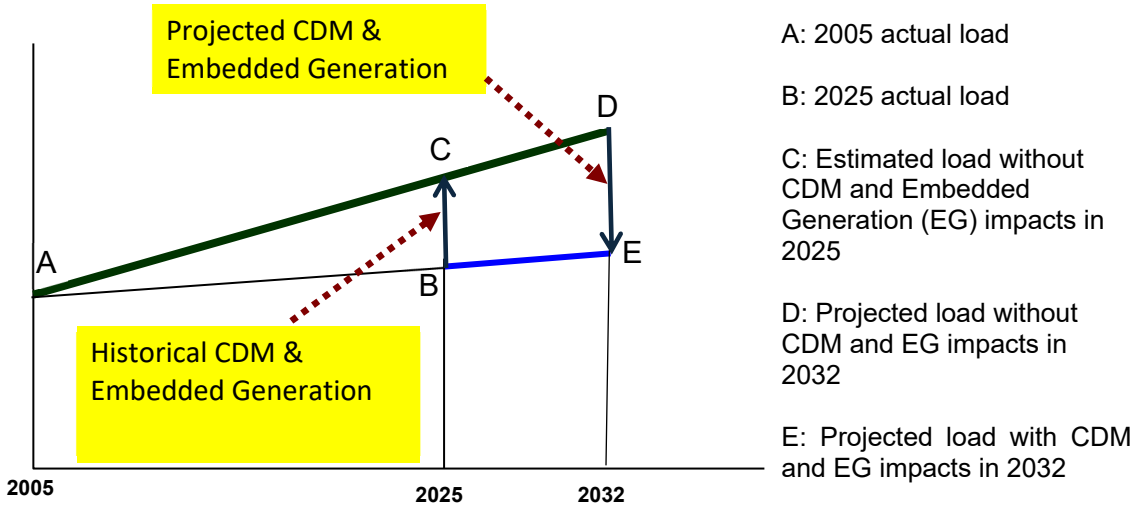


**Figure 2: Incorporation of CDM and Embedded Generation in the Load Forecast**

The derivation of each of the customer forecast and the customer delivery point forecast is addressed in Sections 4.4 and 4.5 of this Exhibit, respectively.

## 4.1 WEATHER CORRECTION ANALYSIS

Weather correction analysis is a statistical process that removes the abnormal or extreme weather effects from the load data to yield average conditions that reflect the normal or expected weather that is used in the forecast. This is essential because the volatility of abnormal or extreme weather conditions can adversely impact the provision of a consistent and accurate forecast for load. Hourly load data and hourly weather data of various weather stations across the province are used in the analysis.

## 4.2 HYDRO ONE'S WEATHER CORRECTION METHODOLOGY

Hydro One's weather correction methodology was originally developed by the forecasting and meteorology staff of the former Ontario Hydro. This weather correction methodology has been used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One is a proven technique that has performed well over the years. The same methodology was reviewed and approved by the OEB in previous Hydro One transmission rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110). Normal weather data is based on the average weather conditions experienced over the last 31 years, consistent with the approach used by the IESO and weather specialists and authorities around the world including Environment Canada, National Oceanic and Atmospheric Administration (NOAA) in the United States, and the Met Office in England. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year (2025). Use of 30 years or more of observations to measure the average of series is also supported by the central limit theorem in statistics, asserting that such average would have an approximate normal distribution regardless of the underlying distribution of the series itself. For example, t-distribution can be approximated by normal distribution for 30 or more observations in the sample.

Hydro One's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud opacity and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction should best be done on a daily basis, rather than on a weekly, monthly or an annual basis as timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over a longer period of time. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than any single day's impact.

The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings. Across Ontario, the penetration rate of such loads varies widely. Weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay, so it is important to use data from the appropriate weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects. Data for five weather stations across Ontario are used in the analysis. They include Toronto, Windsor, Ottawa, North Bay and Thunder Bay. Each delivery point is linked to the closest weather station.

## 4.3 HYDRO ONE FORECASTING METHODOLOGY

Hydro One's transmission system load forecast is developed using a combination of complementary forecasting approaches, each described in the sections that follow. As set out in Exhibit D-03-01, key information used in the analysis includes economic data, demographics, industrial production and commercial floor space, based on economic forecast. The purpose of using these complementary approaches is to arrive at a balanced forecast that is consistent from both a macro and a micro perspective. This is the same load forecast methodology used and approved by the OEB in previous Hydro One rate

applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110), with a refined end-use analysis to account for current and available information.

### 4.3.1 MONTHLY ECONOMETRIC MODEL

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the total transmission system load. The model links monthly energy consumption to Ontario GDP and residential building permits. The load impacts of CDM and embedded generation are added back to the historical data set during the modelling process. The transmission system load used in the model is weather-normal. Appendix A to this Exhibit provides the detailed regression equations and definitions.

### 4.3.2 ANNUAL ECONOMETRIC MODELS

The annual econometric models cover five sectors of the economy: residential, commercial, industrial, agricultural, and transportation. Appendix B to this Exhibit provides the detailed regression equations and definitions.

Hydro One has looked at the alternate data sources available for forecast energy prices and is using the Canada Energy Regulator (CER), formerly the National Energy Board (NEB), as the consistent data source. Since the CER does not provide a forecast for the price of coal, Hydro One produced the forecast in a manner consistent with latest information on the Natural Resources Canada site and trends in other energy prices by CER to retain consistency amongst energy price forecasts.

*Modelling by Sector*

The **residential** sector is modelled as a two-equation system for saturation and usage of electric equipment. Explanatory variables used include energy prices, personal disposable income per household and weather conditions as measured by heating degree days.

The **commercial** sector links energy usage to electricity and natural gas prices, commercial GDP and weather conditions as measured by cooling degree days.

The **industrial** sector is modelled by an equation for total energy and a two-equation model to determine shares of electricity usage. Total energy is modelled as a function of energy price and industrial GDP. The share of each fuel source in total energy is linked to relative energy prices. Dummy variables are used to capture unusual changes in energy growth in the 70's and early 80's and to measure the impact of technical change and the retirement of coal-fired generating stations on the share of each fuel source in total energy.

The **agricultural** sector is modelled in relation to population, while accounting for cyclical and trend changes.

The **transportation** sector, which consists mainly of pipeline and road transport, is modelled by an equation relating electricity usage to electricity and natural gas prices as well as cooling degree days.

### 4.3.3 END-USE ANALYSIS

Traditionally, the end-use analysis covers the residential, commercial, industrial, agricultural and transportation sectors. As in the case of monthly and annual econometric models previously discussed, the resulting forecast is gross of the load impact of CDM and embedded generation.

However, there has been a growing difficulty in updating the end-use models due to lack of detailed information required for doing so. On the other hand, there has also been a growing interest amongst system planners about end-use information related to certain items (e.g., EVs and heat pumps). The general tendency amongst load forecasting institutions (e.g., IESO, Hydro One, EPRI, etc.) has been to reduce reliance on the traditional end-use forecasting in favour of less granular forecasting methods that would be practical. Following this general trend and methodology used by EPRI (which was originated in the European Union, and the Trottier Institute within McGill University in Canada), Hydro One uses an encompassing approach to end-use forecasting of different categories as described in Appendix C to this Exhibit.

## 4.4 METHODOLOGY FOR CUSTOMER FORECAST

In 2026, Hydro One conducted a customer load forecast survey with customers with more than 5 MW of load. The survey also covered the station service load requirements of generating stations when not producing electricity. In addition to questions relating to the total load of the customer, information at each of the delivery points was also collected. The customer survey results are used in the preparation of the customer forecast.

In addition to the information contained in the customer survey, a number of forecasting techniques are used to prepare the load forecast by customer. For large utility customers, each customer is modelled individually using the econometric approach, while accounting for survey results when available. The drivers used in these models include provincial economic variables such as Ontario GDP, population, number of households, energy prices, as well as local demographic and economic variables such as population, households, and production (related GDP). The impact of weather conditions on load is also taken into account. The best subset of the drivers is selected on the basis of regression criteria.

Generally, for industrial customers, several information sources are used to prepare their forecast. With respect to transmission-connected customers, the following information is used:

- historical load profile of the customer;
- knowledge of the customer through industry monitoring;
- forecast provided by customer through the survey;
- company information from Hydro One Transmission account executives, industry and company forecasts from industry associations and government agencies; and
- production and industry forecasts from the economic forecast.

## 4.5 METHODOLOGY FOR CUSTOMER DELIVERY POINT FORECAST

This section discusses the forecasting methodology for the customer delivery point forecast. EPRI's Hourly Electric Load Model (HELM) was used to develop the hourly load shape for each delivery point, taking out abnormal weather effects and load patterns. Key information used in analyzing the load shape for each delivery point includes hourly load and weather data from the weather station closest to each delivery point. The weather stations that were used include Thunder Bay, Windsor, Toronto, Ottawa, and North Bay. The load growth for each delivery point is linked to the customer forecast discussed above. The forecasts for all customer delivery points add up to the regional and the total transmission system forecast.

The most updated customer totalization table[2] is used to retrieve hourly peak demand data for each of the customer delivery points connected to the transmission system. The totalization table reflects the latest records from Hydro One and the IESO as of the time of the load forecast preparation. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. For load analysis purposes, a distinction is made based on whether a delivery point is weather-sensitive or not. Hourly weather data is also retrieved to prepare weather sensitivity analysis as discussed in Section 4.1 above.

In preparing the database for the load shape analysis, missing values are estimated by using the load on a similar day and hour during the same month. For weather-sensitive load, local weather conditions are also taken into account in estimating the missing values.

The HELM is used to prepare the hourly weather response analysis by each delivery point. The model takes into account differences in load depending upon the time (weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such is forecast in relation to load on a similar day and

[2] The totalization table shows whether the customers pay Network, Line Connection and Transformation Connection charges, which is relevant for establishing the charge determinant forecast for each transmission service.

hour during the historical period. The customer forecast is used to drive the customer delivery point forecast. The resulting customer delivery point forecast is therefore consistent with the customer load forecast and the total transmission forecast as discussed above. The charge determinant forecasts at the delivery point level add up to the total charge determinant forecasts presented in Table 3a and Table 3b in the next section.

## 5.0 LOAD FORECAST FOR 2026 TO 2032

Tables 3a and 3b present Hydro One and HOSSM forecasts, which were prepared for this Application before and after deducting the load impacts attributed to embedded generation and CDM for the period 2024 to 2032. The charge determinant forecast is based on the methodology approved by the OEB in its Decisions for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082 and EB-2021-0110, with a refined end-use analysis to account for current and available information. Appendix D to this Exhibit provides the historical actual and weather-corrected charge determinant data for years 2021 to 2025.

Before adjusting for the load impacts arising from embedded generation and CDM, Ontario peak demand is forecast to transmit an average of 24,460 MW in 2026 (12-month average peak), 24,658 MW in 2027, 24,892 MW in 2028, 25,152 MW in 2029, 25,509 MW in 2030, 25,846 MW in 2031, and 26,181 MW in 2032.

After deducting the load impacts of embedded generation and CDM, Ontario peak demand is forecast to transmit an average of 20,534 MW in 2026 (12-month average peak), 20,658 MW in 2027, 20,800 MW in 2028, 20,970 MW in 2029, 21,251 MW in 2030, 21,586 MW in 2031, and 21,949 MW in 2032.

**Table 3a - Hydro One Load Forecast Before and After Embedded Generation and CDM (12-month Average peak in MW)**

| | | Charge Determinants | | |
|---|---|---|---|---|
| | Ontario | Network | Line | Transformation |
| Year | Demand | | Connection | Connection |
| **Load Forecast Before Deducting Load Impact of Embedded Generation and CDM** | | | | |
| 2024 | 23,854 | 24,040 | 23,224 | 19,487 |
| 2025 | 24,124 | 24,326 | 23,780 | 19,738 |
| 2026 | 24,460 | 24,665 | 24,111 | 20,013 |
| 2027 | 24,658 | 24,865 | 24,307 | 20,175 |
| 2028 | 24,892 | 25,101 | 24,538 | 20,367 |
| 2029 | 25,152 | 25,363 | 24,793 | 20,579 |
| 2030 | 25,509 | 25,722 | 25,145 | 20,871 |
| 2031 | 25,846 | 26,062 | 25,478 | 21,147 |
| 2032 | 26,181 | 26,400 | 25,808 | 21,421 |
| | | | | |
| **Load Impact of Embedded Generation** | | | | |
| 2024 | 673 | 678 | 509 | 427 |
| 2025 | 673 | 678 | 515 | 428 |
| 2026 | 756 | 762 | 575 | 478 |
| 2027 | 759 | 765 | 577 | 479 |
| 2028 | 722 | 728 | 550 | 456 |
| 2029 | 699 | 705 | 532 | 442 |
| 2030 | 670 | 675 | 510 | 423 |
| 2031 | 606 | 611 | 461 | 383 |
| 2032 | 535 | 539 | 407 | 338 |
| | | | | |
| **Load Impact of CDM** | | | | |
| 2024 | 2,742 | 2,763 | 2,687 | 2,254 |
| 2025 | 2,966 | 2,991 | 2,943 | 2,443 |
| 2026 | 3,169 | 3,196 | 3,124 | 2,593 |
| 2027 | 3,242 | 3,269 | 3,196 | 2,653 |
| 2028 | 3,370 | 3,398 | 3,322 | 2,757 |
| 2029 | 3,483 | 3,512 | 3,434 | 2,850 |
| 2030 | 3,588 | 3,619 | 3,537 | 2,936 |
| 2031 | 3,655 | 3,685 | 3,602 | 2,990 |
| 2032 | 3,697 | 3,728 | 3,644 | 3,025 |
| | | | | |
| **Load Forecast After Deducting Load Impact of Embedded Generation and CDM** | | | | |
| 2024 | 20,439 | 20,599 | 20,028 | 16,805 |
| 2025 | 20,485 | 20,656 | 20,322 | 16,868 |
| 2026 | 20,534 | 20,706 | 20,411 | 16,942 |
| 2027 | 20,658 | 20,831 | 20,534 | 17,044 |

| | | | | |
|---|---|---|---|---|
| 2028 | 20,800 | 20,975 | 20,666 | 17,153 |
| 2029 | 20,970 | 21,145 | 20,828 | 17,288 |
| 2030 | 21,251 | 21,429 | 21,098 | 17,512 |
| 2031 | 21,586 | 21,766 | 21,414 | 17,774 |
| 2032 | 21,949 | 22,133 | 21,756 | 18,058 |

**Table 3b - HOSSM Load Forecast Before and After Embedded Generation and CDM (12-month Average peak in MW)**

| Year | Charge Determinants | | |
|---|---|---|---|
| | Network | Line Connection | Transformation Connection |
| **Load Forecast Before Deducting Load Impact of Embedded Generation and CDM** | | | |
| 2024 | 308 | 252 | 54 |
| 2025 | 299 | 260 | 53 |
| 2026 | 303 | 264 | 53 |
| 2027 | 306 | 266 | 54 |
| 2028 | 308 | 268 | 54 |
| 2029 | 312 | 271 | 55 |
| 2030 | 316 | 275 | 56 |
| 2031 | 320 | 279 | 56 |
| 2032 | 324 | 282 | 57 |
| **Load Impact of Embedded Generation** | | | |
| 2024 | 8.7 | 5.5 | 1.2 |
| 2025 | 8.3 | 5.6 | 1.1 |
| 2026 | 9.4 | 6.3 | 1.3 |
| 2027 | 9.4 | 6.3 | 1.3 |
| 2028 | 9.0 | 6.0 | 1.2 |
| 2029 | 8.7 | 5.8 | 1.2 |
| 2030 | 8.3 | 5.6 | 1.1 |
| 2031 | 7.5 | 5.0 | 1.0 |
| 2032 | 6.6 | 4.5 | 0.9 |
| **Load Impact of CDM** | | | |
| 2024 | 35 | 29 | 6 |
| 2025 | 37 | 32 | 7 |
| 2026 | 39 | 34 | 7 |
| 2027 | 40 | 35 | 7 |
| 2028 | 42 | 36 | 7 |
| 2029 | 43 | 38 | 8 |
| 2030 | 44 | 39 | 8 |
| 2031 | 45 | 39 | 8 |
| 2032 | 46 | 40 | 8 |
| **Load Forecast After Deducting Load Impact of Embedded Generation and CDM** | | | |
| 2024 | 264 | 217 | 47 |

| | | | |
|---|---|---|---|
| 2025 | 254 | 222 | 45 |
| 2026 | 254 | 223 | 45 |
| 2027 | 256 | 225 | 46 |
| 2028 | 258 | 226 | 46 |
| 2029 | 260 | 228 | 46 |
| 2030 | 263 | 231 | 47 |
| 2031 | 267 | 234 | 47 |
| 2032 | 272 | 238 | 48 |

The 2028 Ontario Demand forecast is 7.3% higher relative to the currently approved 2027 forecast of 19,392 MW, which was forecast in 2021 as part of EB-2021-0110, mainly due to an increase in the base year (2025) load, followed by relatively smaller increases in 2026 to 2028.

In the year 2025 and 2024, the actual Ontario peak demand was 5.6% and 4.0% higher compared to the approved forecast, respectively. [3] The increase is mainly due to a significant increase in immigration targets (from historical average of 0.3 million per year to 0.5 million per year) during the years 2022 to mid-2025, which led to increases in business activity and housing developments, and thus demand for electricity. Subsequently, to address high inflation that had driven up cost of living and cost of doing business significantly, the government started reducing immigration targets back to normal levels, while some lag impacts of high immigration on load continued.

Tables 4a and 4b present, respectively, the upper and lower bands associated with one standard deviation for the Hydro One and HOSSM charge determinant forecasts. Based on historical data, there is a two-in-three chance that the actual load between the years 2026 and 2032 will fall within the upper and lower bands. The bands are derived using a Monte Carlo simulation technique.

[3] Using data for 2024: 20,439 MW Actual vs. 19,650 MW Approved, and for 2025: 20,485 MW Actual vs. 19,402 MW Approved.

**Table 4a - One Standard Deviation Uncertainty Bands for Hydro One Transmission's Charge Determinants (12-Month Average Peak in MW)**

| Year / Network | Lower Band | Forecast | Upper Band |
|---|---|---|---|
| 2025 (Actual) | 20,656 | 20,656 | 20,656 |
| 2026 | 20,376 | 20,706 | 21,040 |
| 2027 | 20,325 | 20,831 | 21,339 |
| 2028 | 20,414 | 20,975 | 21,534 |
| 2029 | 20,474 | 21,145 | 21,814 |
| 2030 | 20,603 | 21,429 | 22,251 |
| 2031 | 20,863 | 21,766 | 22,666 |
| 2032 | 21,037 | 22,133 | 23,225 |
| **Line Connection** | | | |
| 2025 (Actual) | 20,322 | 20,322 | 20,322 |
| 2026 | 20,086 | 20,411 | 20,741 |
| 2027 | 20,035 | 20,534 | 21,035 |
| 2028 | 20,113 | 20,666 | 21,217 |
| 2029 | 20,167 | 20,828 | 21,486 |
| 2030 | 20,285 | 21,098 | 21,908 |
| 2031 | 20,526 | 21,414 | 22,299 |
| 2032 | 20,679 | 21,756 | 22,830 |
| **Transformation Connection** | | | |
| 2025 (Actual) | 16,868 | 16,868 | 16,868 |
| 2026 | 16,672 | 16,942 | 17,215 |
| 2027 | 16,630 | 17,044 | 17,460 |
| 2028 | 16,695 | 17,153 | 17,611 |
| 2029 | 16,739 | 17,288 | 17,834 |
| 2030 | 16,837 | 17,512 | 18,184 |
| 2031 | 17,037 | 17,774 | 18,509 |
| 2032 | 17,164 | 18,058 | 18,949 |

**Table 4b - One Standard Deviation Uncertainty Bands for HOSSM's Charge Determinants (12-Month Average Peak in MW)**

| Year / Network | Lower Band | Forecast | Upper Band |
|---|---|---|---|
| 2025 (Actual) | 254 | 254 | 254 |
| 2026 | 246 | 254 | 263 |
| 2027 | 243 | 256 | 269 |
| 2028 | 244 | 258 | 272 |
| 2029 | 243 | 260 | 276 |
| 2030 | 243 | 263 | 284 |
| 2031 | 245 | 267 | 290 |
| 2032 | 245 | 272 | 299 |
| **Line Connection** | | | |
| 2025 (Actual) | 222 | 222 | 222 |
| 2026 | 216 | 223 | 230 |
| 2027 | 214 | 225 | 236 |
| 2028 | 214 | 226 | 238 |
| 2029 | 213 | 228 | 242 |
| 2030 | 213 | 231 | 249 |
| 2031 | 215 | 234 | 254 |
| 2032 | 214 | 238 | 262 |
| **Transformation Connection** | | | |
| 2025 (Actual) | 45 | 45 | 45 |
| 2026 | 44 | 45 | 47 |
| 2027 | 43 | 46 | 48 |
| 2028 | 43 | 46 | 48 |
| 2029 | 43 | 46 | 49 |
| 2030 | 43 | 47 | 50 |
| 2031 | 43 | 47 | 51 |
| 2032 | 43 | 48 | 53 |

## 6.0 VARIABILITY OF HYDRO ONE'S LOAD FORECASTS

Hydro One has significant expertise in preparing provincial electricity demand forecasts as well as hourly load shape analysis. As part of the load research work associated with EB-2005-0317, Hydro One prepared the load shape analysis for over 80 Local Distribution Companies (LDCs) in Ontario for use in their distribution rate applications to the OEB. The performance of Hydro One's transmission system load forecast since 1999 has been consistently accurate as shown in Table 5.

The higher variances associated with 2022 and 2023 in Table 5 are largely attributable to the increase in immigration targets (from historical average of 0.3 million per year to 0.5 million per year), which significantly increased the number of customers and, thereby, demand for electricity.

**Table 5 - Comparison of Average Monthly Transmission Peak Demand Forecast with Actual**
**(Variance of forecast as percentage of actual on weather corrected basis)**

| Forecast Made in Year | Variance for 1st Year | Variance for 2nd Year | Variance for 3rd Year |
|---|---|---|---|
| 1999 | -0.92% | -2.22% | -2.30% |
| 2000 | 0.18% | 0.26% | 0.22% |
| 2001 | -0.14% | -0.29% | 0.41% |
| 2002 | 0.15% | 0.36% | -0.14% |
| 2003 | 0.25% | 0.09% | 0.83% |
| 2004 | 0.08% | 0.59% | 0.89% |
| 2005 | 0.17% | 0.36% | 0.97% |
| 2006 | -0.69% | 0.41% | 0.15% |
| 2007 | 0.93% | 0.18% | 0.70% |
| 2008 | -0.38% | 0.24% | 0.24% |
| 2009 | -0.23% | -0.88% | 0.83% |
| 2010 | 1.00% | 0.32% | -0.28% |
| 2011 | -0.40% | -1.35% | -2.58% |
| 2012 | -0.05% | -0.20% | -3.47% |
| 2013 | -0.22% | -3.46% | -1.69% |
| 2014 | -0.68% | 1.94% | 2.66% |
| 2015 | 1.50% | 1.19% | 4.14% |
| 2016 | -0.20% | 3.43% | 3.66% |
| 2017 | 0.69% | 0.17% | 0.17% |
| 2018 | -0.95% | -1.38% | -0.94% |
| 2019 | 0.10% | 1.91% | 1.09% |
| 2020 | -0.32% | 1.13% | -0.10% |
| 2021 | 0.50% | -0.16% | -2.63% |
| 2022 | -0.04% | -1.88% | -3.86% |
| 2023 | -1.70% | -3.15% | -3.07% |

| | | | |
|---|---|---|---|
| 2024 | -2.27% | -1.96% | N/A |
| 2025 | -2.25% | N/A | N/A |
| | | | |
| Mean | -0.22 | -0.17 | -0.23 |
| One standard deviation (+/-) | 1.70 | 2.52 | 2.72 |

*Note: The forecasts are net of the load impact of CDM and embedded generation and are compared to the weather corrected actual.*

Between 1999 and 2025, the average variance of the transmission peak-demand forecast compared to the weather corrected actual peak is well within one standard deviation, meaning there is a one-in-three chance that the actual peak demand will be outside of the plus or minus one standard deviation range.

Forecast accuracy for previous OEB-approved forecasts of charge determinants is presented in Table 6. The figures reflect the percent deviation of the forecast for each charge determinant over the forecast period compared to the historical actual on a weather corrected basis. The 2006-2008 forecasts were approved by the OEB in EB-2006-0501. Similarly, the 2008-2012 through 2023-2027 forecasts were approved in proceedings EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110. Detailed comparison of forecasts for each forecast year separately is provided in Appendix E which includes Tables 6a to 6c.

**Table 6**
**Historical Board Approved Forecasts**
**vs. Historical Actual-Weather Corrected**

| | Difference from Actual-Weather Corrected (%) * | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Type of Connection | EB-2006-0501 Forecast | EB-2008-0272 Forecast | EB-2010-0002 Forecast | EB-2012-0031 Forecast | EB-2014-0140 Forecast | EB-2016-0160 Forecast | EB-2019-0082 Forecast | EB-2021-0110 Forecast | **Average** |
| Network | -0.49 | -0.45 | -0.42 | -2.10 | 0.89 | 2.46 | 1.88 | -3.91 | **-0.27** |
| Line | -0.71 | 0.79 | 0.68 | -0.83 | 1.27 | 1.84 | 2.25 | -4.23 | **0.13** |
| Transformation | -1.02 | 0.16 | 0.52 | -0.37 | 1.71 | 2.36 | 2.27 | -3.24 | **0.30** |
| **Average** | **-0.74** | **0.17** | **0.26** | **-1.10** | **1.29** | **2.22** | **2.13** | **-3.79** | **0.06** |
| One Standard Deviation (+/-) ** | 2.26 | 2.26 | 2.26 | 2.26 | 2.26 | 2.26 | 2.26 | 2.26 | |

* A negative (positive) variance shows that the forecast was below (above) actual.
** Reflects expected deviation of forecast from actual-weather corrected based on historical variations. All forecast are within 90% confidence interval.
Note. EB-2014-0140, EB-2019-0082, and EB-2021-0110 approved forecasts were the modified forecasts.

As shown in Table 6, the deviations of previous OEB-approved charge determinant forecasts from historical actuals on a weather-corrected basis are within the 90% confidence interval, and the average deviation over the past eight OEB-approved forecasts (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110) is close to zero.

## Appendix A – Monthly Econometric Model

The monthly econometric model uses the State-Space Approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that affect the energy estimates as these events can cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LWCTSE = f (LGDPONT, LBPONT, D0803)

where:

LWCTSE = logarithm of Networks' load,

- Based on hourly figures for Ontario Demand from IESO

LGDPONT = logarithm of Ontario GDP in chained 2017 dollars,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance
- Forecast is based on annual consensus forecast for Ontario GDP as presented in Appendix A of Exhibit D-03-01

LBPONT = logarithm of Ontario residential building permits in constant dollar,

- History is based on monthly value of Ontario residential building permits from Statistics Canada
- Forecast is based on consensus forecast of housing starts as presented in Appendix A of Exhibit D-03-01

D0803 = dummy variable for the August 2003 Blackout, equals 1 in that month and zero elsewhere.

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

Seasonal SS parameters:

| | |
|---|---|
| A[1] | 0.0696941 |
| K[1] | -0.544751 |

Non-seasonal:

Short memory SS parameters:

| | | | | |
|---|---|---|---|---|
| A[1] | 1.08892 | | | |
| A[2] | -0.837902 | | | |
| A[3] | 0.253521 | | | |
| K[1] | -0.356613 | | | |
| K[2] | -0.230819 | | | |
| K[3] | -0.137841 | | | |
| GDPONT | LOG | 1 | 1 | Exogenous |
| G[1][1] | 0.528014 | | | |
| G[2][1] | 0.00841705 | | | |
| G[3][1] | -0.140744 | | | |
| BPONT[-8] | LOG | 1 | 1 | Exogenous |
| G[1][2] | 0.00172613 | | | |
| G[2][2] | 0.000654328 | | | |
| G[3][2] | -0.000435245 | | | |
| D0803 | 1 | 1 | Exogenous | |
| G[1][3] | -0.0264203 | | | |
| G[2][3] | -5.72E-05 | | | |
| G[3][3] | 0.0112672 | | | |

R-squared = 0.995, R-squared corrected for mean = 0.995, Durbin-Watson Statistics = 2.13

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain the variations in load. The regression results show that the fit is very good and there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the parameters are used in the monthly regression equation to generate the forecast for the transmission system load.

# Appendix B – Annual Econometric Model

In this Appendix, regression results for annual econometric models are presented.

## Residential Model

Residential sector equations consist of a saturation equation and a use equation. Saturation at year t is measured as sum of penetration of household equipment i at year t, Ei (t) – which is measured as the percentage of households using that equipment - multiplied by the annual electricity usage of equipment i in 2024(Ui); normalized to be 1 in 2024:

Saturation (t) = (S Ei (t) * Ui ) / (S Ei (2024) * Ui )

Usage at year t is measured as the ratio of per household residential consumption to saturation in that year, again normalized to be 1 in 2024.

Usage (t) = [(per household consumption (t))/ Saturation (t)] /
[per household consumption (2024) / Saturation (2024)]

Ontario residential electricity consumption can then be calculated as:

Total residential electricity consumption = Saturation (t) * Usage (t) * N(t)
where N(t) is a normalizing factor to account for the number of households in Ontario in year t multiplied by per household consumption in 2024.

Saturation and usage are modelled as a function of energy prices, income per household in Ontario, lagged value of saturation and usage, heating degree days and two dummy variables:

```
LELSAT= C(1)*(LPELRES+LPELRES(-1))/2 + C(2)*LYPDPHH
      + C(3)*LELSAT(-1) + C(4)*LELSAT(-2) + C(5)*D81
LELUSE = C(6)*(2*LPELRES(-4)-LPLIQRES(-4)) + C(7)
```

*LYPDPHH + C(8)*LHDD^0.4 + (1 + C(9) + C(10))*LELUSE(-1) +
C(9)*LELSAT + C(10)*LELSAT(-1)-C(8)* (1 + C(9) + C(10))
*LHDD(-1) + C(11)*TR3

where:

LELSAT = logarithm of residential electricity saturation in Ontario,

- History is constructed from residential load, number of households and Survey of Household Spending by Statistics Canada, and associated load impact of CDM

LPELRES = logarithm of electricity price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026
- Forecast is from CER 2026 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPLIQRES = logarithm of liquid-fuel price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026 Outlook,
- Forecast is based on CER 2026 Outlook, includes carbon tax

LYPDPHH = logarithm of Ontario personal disposable income per household /house in constant $,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistics Canada, and divided by the number of households / houses based on S&P Global housing starts,
- Forecast is based on forecasts of disposable income from Stokes Economics (C4SE) and Signal49 Research (Conference Board of Canada), CPI from Signal49, and number of households is based on consensus forecast of housing starts as presented in Appendix A of Exhibit D-03-01.

D81 = dummy variable to account for an outlier, equals 1 in 1981, 0 elsewhere,

LELUSE = logarithm of residential electricity usage in Ontario,

- History is constructed from residential load, number of households and Survey of Household Spending by Statistics Canada, and associated load impact of CDM

LHDD = logarithm of heating-degree-days for Pearson International Airport,

- History is from Environment Canada
- Forecast is 31-year average of historical annual HDD figures

TR3 = dummy variable to capture trend, equals 1 in 1961 and increases by 1 per year thereafter.

c(1) to c(11) = variable coefficients.

The equations are estimated simultaneously using 3-Stage Least Squares, using actual heating degree days for the Toronto weather station:

| | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C(1) | -0.058713 | 0.014433 | -4.067933 | 0.0001 |
| C(2) | 0.158431 | 0.038901 | 4.072623 | 0.0001 |
| C(3) | 0.605463 | 0.118342 | 5.116226 | 0 |
| C(4) | 0.279876 | 0.110561 | 2.531421 | 0.0128 |
| C(5) | -0.037458 | 0.019383 | -1.93257 | 0.0559 |
| C(6) | -0.01908 | 0.014196 | -1.3441 | 0.1817 |
| C(7) | 0.181685 | 0.065719 | 2.76459 | 0.0067 |
| C(8) | 0.090386 | 0.06147 | 1.4704 | 0.1443 |
| C(9) | -1.064392 | 0.3047 | -3.493245 | 0.0007 |
| C(10) | 0.935858 | 0.291807 | 3.207117 | 0.0018 |
| C(11) | -0.001737 | 0.000787 | -2.206452 | 0.0294 |

Saturation Model Fit:

R-squared =0.97, Adjusted R-squared = 0.97, Durbin-Watson Statistics =2.08

Usage Model Fit:

R-squared =0.95, Adjusted R-squared = 0.95, Durbin-Watson Statistics =1.77

The regression results show the goodness of fit of the model, as measured by (Adjusted) R-square, is good. The t-ratios also show that all the factors used to explain the variations in load are statistically significant at 82% probability level or higher. Using the forecast values

for personal disposable income, energy prices, heating degree days and dummy variables, the parameters are used in the annual regression equation to generate the forecast for the residential load.

**Commercial Model**

The commercial model uses the price of electricity and of natural gas, commercial GDP and cooling degree days to forecast the commercial load. The commercial model can be represented by the following equation:

LELCOM = C(1)*(LPELCOM-LPGASCOM)*(D07B*LOG(ELCOM(-1)
/GDPCOM(-1))+1)+C(2)*(LGDPCOM(-1))+C(3)*LELCOM(-1)
+C(4)*LCDD+C(5)*D(LELCOM(-1))

where

LELCOM = logarithm of electricity consumption in Ontario commercial sector,

- History is based on commercial load from Statistics Canada, and associated load impact of CDM

LPELCOM = logarithm of price of electricity in the commercial sector,

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026 Outlook,
- Forecast is from CER 2026 Outlook,

LPGASCOM = logarithm of price of natural gas in the commercial sector,

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026 Outlook,
- Forecast is based on CER 2026 Outlook, includes carbon tax

LGDPCOM = logarithm of Ontario commercial GDP in constant $,

- History is from Statistics Canada figures for GDP by industry,
- Forecast is prepared by Hydro One in a manner consistent with consensus forecast as presented in Appendix A of Exhibit D-03-01.

LCDD = logarithm of cooling-degree-days for Pearson International Airport.

- History is from Environment Canada,
- Forecast is 31-year average of historical annual CDD figures

D07B = dummy variable to account for change in price elasticity, equals 1 before 2007 and 0 otherwise.

The estimated equation is presented below:

| | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C(1) | -0.026115 | 0.005297 | -4.930018 | 0 |
| C(2) | 0.097009 | 0.023446 | 4.137622 | 0.0001 |
| C(3) | 0.872602 | 0.025663 | 34.00185 | 0 |
| C(4) | 0.024968 | 0.013057 | 1.912317 | 0.061 |
| C(5) | 0.1133 | 0.117923 | 0.960795 | 0.3409 |

R-squared =0.998, Adjusted R-squared = 0.998, Durbin-Watson Statistics =2.09

The regression results reflect a high goodness of fit and statistical significance for all estimates at 66% probability level or higher.

**Industrial Model**

The industrial load is modelled as one source of energy in the industrial sector of Ontario economy. The model consists of an equation for total energy and a 2-equation model to determine share of electricity usage out of the total energy.

The total energy model is represented by the following equation:

LENIND=C(1)+C(2)*LGDPIND+C(3)*LGDPIND(-1)+C(4)
*LOG(ENIND(-1))+C(5)*(LOG(PENIND)+LOG(PENIND(-8))/2+C(6)*D13+C(7)*D1415

where

LENIND = logarithm of electricity consumption in Ontario industrial sector,

- History is based on energy series from Statistics Canada, and associated load impact of CDM

PENIND = logarithm of price of energy in the industrial sector, defined as the weighted average of price of electricity, liquid fuel and coal in that sector,

- History of energy prices, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP, CER 2026 Outlook, and National Research Council Canada
- Forecast is from Hydro One for coal and CER 2026 Outlook for other energy prices, includes carbon tax

LGDPIND = logarithm of Ontario industrial GDP in constant $,

- History is from Statistics Canada figures for GDP by industry
- Forecast is prepared by Hydro One in a manner consistent with consensus forecast as presented in Appendix A of Exhibit D-03-01.

D13 = a dummy variable, equals 1 in 2013 and zero elsewhere.

D1415 = a dummy variable, equals 1 in 2014, -1 in 2015, and zero elsewhere.

The estimated model is presented as follows:

| | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C(1) | 2.222552 | 0.73498 | 3.023962 | 0.004 |
| C(2) | 0.624963 | 0.086093 | 7.259126 | 0 |
| C(3) | -0.556736 | 0.089146 | -6.245203 | 0 |
| C(4) | 0.779218 | 0.057393 | 13.57684 | 0 |
| C(5) | -0.033931 | 0.014686 | -2.310424 | 0.0252 |
| C(6) | -0.158676 | 0.036705 | -4.323008 | 0.0001 |
| C(7) | -0.092656 | 0.025423 | -3.644538 | 0.0007 |

R-squared =0.913, Adjusted R-squared = 0.902, Durbin-Watson Statistics =1.90

The regression results show a strong correlation between energy consumption and explanatory variables, despite higher variability in the industrial sector compared to the residential and commercial sectors in Ontario.

The equations for determining the share of electricity in total energy (LW13 and LW23) are:

LW13=C(1)-(W2S*C(12)+(W1S+W3S)*C(13))*LP13
+(C(12)-C(23))*W2S*LP23+C(5)*LT +C(16)*D1415
+[AR(1)=C(60)]

LW23=C(2)-(W1S*C(12)+(W2S+W3S)*C(23))*LP23
+(C(12)-C(13))*W1S*LP13+C(6)*LT+C(26)*D1415+C(7)*DG
+[AR(1)=C(60)]

where

LW13 = logarithm of electricity cost relative to coal in Ontario industrial sector,

LW23 = logarithm of liquid-fuel cost relative to coal in Ontario industrial sector,

W1S, W2S, W3S = quantity share of electricity, liquid fuel and coal in total energy in Ontario, respectively; history of all cost shares is based on energy series and associated energy prices,

LP12 = logarithm of price of electricity relative to liquid fuel in Ontario industrial sector,

LP23 = logarithm of price of liquid fuel relative to coal in Ontario industrial sector,

LP13 = logarithm of price of electricity relative to coal in Ontario industrial sector,

- History of energy prices, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026 Outlook
- Forecast is from Hydro One for price of coal and CER 2026 Outlook for other energy prices, include carbon tax,

DG = dummy variable to account for abnormal changes in energy growth between 1969 and 1982, equals 0.5 in 1969 to 1970, 1 in 1971 to 1982, and 0 elsewhere,

D1415 = Dummy variable, equals 1 in 2014 and -1 in 2015, and 0 elsewhere,

LT = logarithm of a trend variable equals 1 in 1963, increasing by 1 each year thereafter. This would pick up impact of technical change on energy shares apart from movements in relative energy prices.

The equations are estimated using the weighted Seemingly Unrelated Equations (SUR) method. The estimated model is presented as follows:

| | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C(1) | -2.114186 | 0.121192 | -17.4449 | 0 |
| C(12) | -0.927548 | 0.048256 | -19.22143 | 0 |
| C(13) | -1.200379 | 0.066459 | -18.06191 | 0 |
| C(23) | -0.799325 | 0.113832 | -7.02196 | 0 |
| C(5) | 0.57308 | 0.033564 | 17.07448 | 0 |
| C(16) | 0.527057 | 0.195431 | 2.696894 | 0.0081 |
| C(60) | 0.54411 | 0.061423 | 8.858414 | 0 |
| C(2) | -0.766115 | 0.120962 | -6.333502 | 0 |
| C(6) | 0.429666 | 0.032469 | 13.23311 | 0 |
| C(26) | 0.520266 | 0.208688 | 2.49303 | 0.0141 |
| C(7) | 0.21816 | 0.035241 | 6.190439 | 0 |

LW13 Model Fit:

R-squared =0.995, Adjusted R-squared = 0.994, Durbin-Watson Statistics =1.99

LW23 Model Fit:

R-squared =0.995, Adjusted R-squared = 0.994, Durbin-Watson Statistics =1.89

The regression results show the model has a good fit with historical values and all the model parameters are statistically significant.

**Agricultural Model**

The agricultural electricity consumption is affected by population as well as trend and cyclical variations. The agricultural electricity model therefore includes trend and moving average terms in addition to population, as follows:

ELAGR = C(1)+C(2)*D(POPONT(-4))+C(3)*D08+C(4)*D0514+AR(1)+MA(4)

where

ELAGR = electricity consumption in Ontario agricultural sector,

- History is based on agricultural load from Statistics Canada, and associated load impact of CDM.

POPONT = Ontario population,

- History is from Statistics Canada
- Forecast is from Stokes Economics and Signal49 Research

D08 = dummy variable to account for an outlier, equals 1 in 2008, 0 elsewhere,

D0514 = dummy variable to account for a shift in usage, equals 1 in 2005 to 2014, 0 elsewhere,

AR(1) = an autoregressive term of order 1,

MA(4) = a moving average term of order 4.

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C | 2601.142 | 113.4113 | 22.93548 | 0 |
| D(POPONT(-4)) | 0.725506 | 0.686157 | 1.057347 | 0.2988 |
| D08 | 179.8037 | 97.32727 | 1.847413 | 0.0746 |
| D0514 | -321.9178 | 88.88578 | -3.621702 | 0.0011 |
| AR(1) | 0.716786 | 0.137203 | 5.224286 | 0 |
| MA(4) | -0.948389 | 0.024943 | -38.02175 | 0 |

R-squared =0.832, Adjusted R-squared = 0.804, Durbin-Watson Statistics =2.15

The regression results show the model captures most of the variations in the agricultural load in Ontario despite a great volatility in the data series.

**Transportation Model**

The transportation model is represented by an equation basically relating electricity usage to weather conditions as measured by cooling degree days, and price variables.

LTRANS=C(1)+C(2)*LTRANS(-1)+ C(3)*(PELRES-PGASRES)+C(4)
*D0708+C(5)*LCDD+C(6)*D12+C(7)*D98

where

LTRANS = logarithm of electricity consumption in Ontario transportation sector,

- History is based on transportation load from Statistics Canada, and associated load impact of CDM

PELRES = electricity price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026
- Forecast is from CER 2026 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

PGASRES = natural gas price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026
- Forecast is based on CER 2026 Outlook, includes carbon tax,

D0708 = a dummy variable to capture an opposite move in load, equals -1 in 2007 and 1 in 2008.

LCDD = Logarithm of cooling degree days

D12 = a dummy variable to capture drop in load, equals 1 in 2012, 0 elsewhere.

D98 = a dummy variable to capture drop in load, equals 1 in 1998, 0 elsewhere.

Regression results follow:

| | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| C(1) | 1.017415 | 0.556572 | 1.828002 | 0.0758 |
| C(2) | 0.736089 | 0.082359 | 8.937594 | 0 |
| C(3) | -0.094603 | 0.049505 | -1.910979 | 0.064 |
| C(4) | 0.175127 | 0.05624 | 3.113922 | 0.0036 |
| C(5) | 0.137359 | 0.035606 | 3.857706 | 0.0005 |
| C(6) | -0.510034 | 0.082578 | -6.176384 | 0 |
| C(7) | 0.343431 | 0.079905 | 4.297972 | 0.0001 |

R-squared =0.838, Adjusted R-squared = 0.811, Durbin-Watson Statistics =2.13

The model fit is good despite extreme volatility in the transportation electricity consumption in Ontario. However, transportation load is less than 0.5 per cent of Ontario electricity load and, as such, its volatility does not significantly affect the forecast accuracy of total load.

## Appendix C – Load Research and Next Generation (NG) End-Use Analysis

Hydro One maintains a comprehensive load research and end-use analysis program to support transmission load forecasting, system planning, and investment decision-making. These activities provide insights into electricity consumption patterns, sectoral trends, technology adoption, electrification developments, and evolving customer requirements across Ontario.

Hydro One's load research program draws on a variety of sources, including IESO data and studies, Statistics Canada data, EPRI research, OEB reporting, large customer surveys, industrial monitoring activities, and other targeted sectoral studies. Hydro One also monitors developments related to electrification, fuel switching, EVs, industrial decarbonization, distributed energy resources, and emerging technologies. The resulting information is used to support the development, calibration, validation, and ongoing enhancement of Hydro One's forecasting methodologies.

Traditionally, end-use forecasting relied on detailed estimates of electricity consumption by individual appliances, equipment types, building characteristics, and industrial processes. While these methods continue to provide valuable insights, maintaining highly granular end-use forecasting models has become increasingly challenging in the context of rapidly evolving technologies, electrification initiatives, climate policies, and changing customer preferences.

At the same time, there is growing interest among system planners and other stakeholders in understanding the load impacts associated with emerging electrification technologies and applications. Examples include EVs, heat pumps, electrification of transportation, industrial electrification, data centres, battery manufacturing, and other technologies that may influence future electricity demand and load profiles. Accordingly, Hydro One has evolved its forecasting framework by supplementing its traditional load research and end-use analysis activities with a Next Generation (NG) End-Use Analysis focused on key electrification drivers. The objective of the NG End-Use Analysis is not to forecast each

individual appliance or technology separately. Rather, it provides a practical assessment of the principal sources of future load growth arising from electrification and economic transformation. The analysis incorporates observed load trends, sectoral electricity consumption data, technology adoption patterns, economic forecasts, customer information, and relevant government electrification and decarbonization initiatives.

For emerging technologies and applications, adoption is expected to follow growth patterns commonly associated with the introduction and maturation of new technologies. Accordingly, the NG End-Use Analysis incorporates technology adoption trajectories informed by market developments, customer information, industrial monitoring activities, and relevant electrification policies. The resulting estimates are periodically reviewed against observed load data and other available information to ensure continued reasonableness.

Hydro One undertakes ongoing monitoring of large transmission-connected customers and LDCs through load forecast surveys, customer engagement activities, and industry research. Information on electrification initiatives, expansion plans, fuel switching, and other emerging developments is used to inform and validate the transmission load forecast.

The NG End-Use Analysis is used as a supplementary forecasting tool to assess the impact of electrification and structural economic changes on future electricity demand. It provides additional insight into emerging load drivers that may not be fully reflected in historical trends alone and supports Hydro One's assessment of future loading conditions across the transmission system.

The results of the NG End-Use Analysis are considered alongside Hydro One's econometric forecasting methodologies and customer forecast assessments in the development, interpretation, and validation of the transmission load forecast. Collectively, Hydro One's load research program, customer surveys, industrial monitoring activities, NG End-Use Analysis, and econometric forecasting models provide a complementary

framework for assessing future electricity demand and the potential impacts of electrification and economic change.

## Appendix D – Historical Ontario Demand and Charge Determinant Data

This Appendix provides the historical actual and weather corrected Ontario demand, and Hydro One, and HOSSM charge determinants for 2021-2025.

| Actual Ontario Demand, Hydro One and HOSSM Charge Determinants | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (MW) | | | | | | | | | | | | |
| | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
| | | | | | | | | | | | | |
| **Hydro One Transmission** | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| **2021** | | | | | | | | | | | | |
| Ontario Demand | 20,150 | 20,318 | 19,344 | 16,644 | 19,443 | 22,258 | 21,655 | 22,986 | 18,769 | 17,312 | 19,644 | 20,455 |
| Network Connection | 19,789 | 19,953 | 19,222 | 16,837 | 19,444 | 22,787 | 22,415 | 23,760 | 18,841 | 17,454 | 19,412 | 20,157 |
| Line Connection | 18,953 | 19,330 | 18,405 | 16,400 | 18,971 | 22,473 | 21,839 | 23,091 | 18,592 | 17,320 | 18,578 | 19,189 |
| Transformation Connection | 16,153 | 16,495 | 15,632 | 13,756 | 15,915 | 19,223 | 18,716 | 19,883 | 15,710 | 14,543 | 15,690 | 16,290 |
| | | | | | | | | | | | | |
| **2022** | | | | | | | | | | | | |
| Ontario Demand | 21,349 | 20,918 | 19,763 | 17,256 | 21,292 | 21,954 | 22,607 | 21,871 | 20,350 | 17,294 | 19,441 | 20,326 |
| Network Connection | 21,373 | 20,577 | 19,595 | 17,390 | 21,713 | 22,599 | 23,263 | 22,496 | 20,484 | 17,576 | 19,485 | 20,246 |
| Line Connection | 20,270 | 19,679 | 18,730 | 17,074 | 20,982 | 22,330 | 22,599 | 22,490 | 19,938 | 17,249 | 18,899 | 19,900 |
| Transformation Connection | 17,484 | 16,898 | 15,947 | 14,261 | 17,624 | 18,990 | 19,222 | 19,173 | 16,761 | 14,429 | 15,979 | 16,824 |
| | | | | | | | | | | | | |
| **2023** | | | | | | | | | | | | |
| Ontario Demand | 20,486 | 21,388 | 18,811 | 17,547 | 20,787 | 21,463 | 22,686 | 21,364 | 23,713 | 20,849 | 20,579 | 20,004 |
| Network Connection | 20,229 | 21,246 | 18,753 | 17,488 | 20,778 | 21,971 | 23,503 | 21,495 | 24,158 | 20,948 | 20,118 | 19,870 |
| Line Connection | 19,550 | 20,143 | 18,518 | 17,560 | 19,952 | 21,587 | 22,835 | 20,845 | 23,288 | 20,080 | 19,151 | 19,200 |
| Transformation Connection | 16,657 | 17,211 | 15,574 | 14,598 | 16,664 | 18,082 | 19,279 | 17,521 | 19,724 | 16,933 | 16,197 | 16,148 |
| | | | | | | | | | | | | |
| **2024** | | | | | | | | | | | | |
| Ontario Demand | 20,880 | 19,703 | 18,813 | 17,958 | 20,436 | 23,852 | 23,356 | 23,179 | 21,546 | 17,998 | 19,260 | 20,929 |
| Network Connection | 20,969 | 19,774 | 19,011 | 18,081 | 20,573 | 24,352 | 23,739 | 23,619 | 21,387 | 18,463 | 19,116 | 20,792 |
| Line Connection | 20,223 | 19,337 | 18,501 | 17,510 | 19,925 | 23,667 | 23,067 | 23,124 | 20,536 | 18,171 | 18,690 | 20,183 |
| Transformation Connection | 17,199 | 16,196 | 15,383 | 14,517 | 16,500 | 19,866 | 19,524 | 19,641 | 17,292 | 15,117 | 15,570 | 17,058 |
| | | | | | | | | | | | | |
| **2025** | | | | | | | | | | | | |
| Ontario Demand | 21,940 | 21,302 | 20,301 | 19,492 | 18,153 | 24,862 | 24,528 | 24,789 | 19,931 | 20,335 | 19,731 | 21,406 |
| Network Connection | 21,957 | 21,394 | 20,360 | 19,038 | 18,146 | 25,645 | 25,232 | 24,922 | 20,160 | 20,302 | 20,112 | 21,692 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line Connection | 21,035 | 20,620 | 19,875 | 18,713 | 17,947 | 25,200 | 24,850 | 24,572 | 19,930 | 20,058 | 20,083 | 21,858 |
| Transformation Connection | 17,838 | 17,409 | 16,428 | 15,278 | 14,534 | 21,026 | 20,799 | 20,710 | 16,471 | 16,411 | 16,477 | 18,129 |
| | | | | | | | | | | | | |
| **HOSSM** | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| **2021** | | | | | | | | | | | | |
| Network Connection | 270 | 307 | 302 | 237 | 227 | 250 | 233 | 241 | 233 | 234 | 290 | 292 |
| Line Connection | 218 | 219 | 219 | 213 | 215 | 225 | 210 | 215 | 210 | 218 | 217 | 218 |
| Transformation Connection | 46 | 48 | 44 | 41 | 42 | 47 | 38 | 45 | 36 | 39 | 46 | 48 |
| | | | | | | | | | | | | |
| **2022** | | | | | | | | | | | | |
| Network Connection | 306 | 288 | 303 | 269 | 246 | 236 | 241 | 229 | 231 | 261 | 294 | 280 |
| Line Connection | 227 | 222 | 219 | 223 | 205 | 213 | 202 | 205 | 206 | 209 | 221 | 226 |
| Transformation Connection | 53 | 52 | 47 | 44 | 39 | 45 | 37 | 37 | 40 | 43 | 58 | 50 |
| | | | | | | | | | | | | |
| **2023** | | | | | | | | | | | | |
| Network Connection | 303 | 323 | 269 | 243 | 271 | 225 | 239 | 255 | 265 | 260 | 278 | 252 |
| Line Connection | 216 | 219 | 218 | 224 | 219 | 218 | 213 | 217 | 210 | 217 | 218 | 218 |
| Transformation Connection | 50 | 53 | 46 | 46 | 50 | 45 | 39 | 37 | 39 | 41 | 49 | 49 |
| | | | | | | | | | | | | |
| **2024** | | | | | | | | | | | | |
| Network Connection | 277 | 275 | 281 | 250 | 254 | 227 | 235 | 253 | 264 | 267 | 303 | 297 |
| Line Connection | 219 | 221 | 215 | 215 | 223 | 218 | 213 | 216 | 220 | 221 | 223 | 225 |
| Transformation Connection | 52 | 51 | 45 | 53 | 49 | 37 | 39 | 42 | 41 | 45 | 52 | 57 |
| | | | | | | | | | | | | |
| **2025** | | | | | | | | | | | | |
| Network Connection | 291 | 280 | 280 | 279 | 237 | 238 | 254 | 217 | 255 | 262 | 282 | 286 |
| Line Connection | 227 | 218 | 211 | 222 | 246 | 205 | 231 | 201 | 266 | 238 | 252 | 247 |
| Transformation Connection | 56 | 53 | 49 | 57 | 50 | 40 | 39 | 38 | 37 | 40 | 49 | 53 |

*Note: Charge determinant values are proxy numbers calculated based on actual data.*

| Weather Corrected Ontario Demand, Hydro One, and HOSSM Charge Determinants | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (MW) | | | | | | | | | | | | |
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
| | | | | | | | | | | | | |
| **Hydro One Transmission** | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| **2021** | | | | | | | | | | | | |
| Ontario Demand | 19,599 | 19,161 | 18,481 | 16,861 | 18,157 | 20,606 | 21,706 | 20,617 | 19,569 | 17,403 | 18,814 | 19,932 |
| Network Connection | 19,247 | 18,817 | 18,365 | 17,056 | 18,158 | 21,096 | 22,468 | 21,311 | 19,644 | 17,545 | 18,592 | 19,642 |
| Line Connection | 18,434 | 18,230 | 17,585 | 16,613 | 17,717 | 20,805 | 21,891 | 20,711 | 19,385 | 17,410 | 17,793 | 18,699 |
| Transformation Connection | 15,711 | 15,556 | 14,935 | 13,935 | 14,863 | 17,796 | 18,760 | 17,834 | 16,380 | 14,619 | 15,028 | 15,874 |
| | | | | | | | | | | | | |
| **2022** | | | | | | | | | | | | |
| Ontario Demand | 20,189 | 19,418 | 18,876 | 17,176 | 18,273 | 20,835 | 21,357 | 20,773 | 19,586 | 17,402 | 18,932 | 20,123 |
| Network Connection | 20,212 | 19,101 | 18,716 | 17,309 | 18,634 | 21,448 | 21,977 | 21,367 | 19,715 | 17,686 | 18,975 | 20,044 |
| Line Connection | 19,169 | 18,267 | 17,890 | 16,994 | 18,006 | 21,192 | 21,349 | 21,361 | 19,189 | 17,357 | 18,404 | 19,701 |
| Transformation Connection | 16,534 | 15,686 | 15,232 | 14,195 | 15,125 | 18,023 | 18,159 | 18,210 | 16,132 | 14,520 | 15,561 | 16,656 |
| | | | | | | | | | | | | |
| **2023** | | | | | | | | | | | | |
| Ontario Demand | 20,569 | 20,057 | 19,248 | 17,759 | 18,779 | 21,438 | 22,081 | 21,815 | 20,064 | 18,101 | 19,451 | 20,351 |
| Network Connection | 20,311 | 19,924 | 19,189 | 17,699 | 18,771 | 21,946 | 22,876 | 21,949 | 20,441 | 18,186 | 19,015 | 20,215 |
| Line Connection | 19,630 | 18,890 | 18,949 | 17,773 | 18,025 | 21,562 | 22,226 | 21,285 | 19,704 | 17,433 | 18,102 | 19,533 |
| Transformation Connection | 16,725 | 16,141 | 15,936 | 14,775 | 15,055 | 18,061 | 18,765 | 17,891 | 16,689 | 14,701 | 15,309 | 16,428 |
| | | | | | | | | | | | | |
| **2024** | | | | | | | | | | | | |
| Ontario Demand | 21,170 | 20,396 | 19,605 | 18,272 | 19,195 | 21,993 | 22,601 | 21,932 | 20,645 | 18,600 | 19,814 | 21,049 |
| Network Connection | 21,261 | 20,469 | 19,812 | 18,397 | 19,323 | 22,454 | 22,971 | 22,348 | 20,493 | 19,081 | 19,667 | 20,912 |
| Line Connection | 20,504 | 20,017 | 19,280 | 17,816 | 18,715 | 21,822 | 22,321 | 21,880 | 19,677 | 18,779 | 19,227 | 20,299 |
| Transformation Connection | 17,438 | 16,765 | 16,031 | 14,771 | 15,498 | 18,318 | 18,893 | 18,584 | 16,569 | 15,622 | 16,018 | 17,156 |
| | | | | | | | | | | | | |
| **2025** | | | | | | | | | | | | |
| Ontario Demand | 21,263 | 20,666 | 19,894 | 18,228 | 19,139 | 21,871 | 22,587 | 21,927 | 20,644 | 18,584 | 19,888 | 21,125 |
| Network Connection | 21,280 | 20,755 | 19,951 | 17,804 | 19,132 | 22,560 | 23,235 | 22,045 | 20,881 | 18,554 | 20,272 | 21,408 |
| Line Connection | 20,385 | 20,005 | 19,476 | 17,500 | 18,922 | 22,168 | 22,883 | 21,735 | 20,643 | 18,331 | 20,243 | 21,572 |
| Transformation Connection | 17,288 | 16,890 | 16,098 | 14,287 | 15,324 | 18,497 | 19,153 | 18,319 | 17,060 | 14,998 | 16,609 | 17,891 |

| **HOSSM** | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | |
| **2021** | | | | | | | | | | | | |
| Network Connection | 263 | 290 | 289 | 240 | 212 | 231 | 233 | 216 | 243 | 235 | 278 | 284 |
| Line Connection | 212 | 206 | 209 | 216 | 200 | 208 | 211 | 193 | 219 | 219 | 208 | 213 |
| Transformation Connection | 44 | 45 | 42 | 42 | 40 | 43 | 38 | 40 | 38 | 39 | 44 | 46 |
| | | | | | | | | | | | | |
| **2022** | | | | | | | | | | | | |
| Network Connection | 289 | 268 | 289 | 267 | 211 | 224 | 228 | 218 | 223 | 263 | 286 | 278 |
| Line Connection | 214 | 206 | 210 | 221 | 176 | 203 | 191 | 194 | 199 | 210 | 215 | 223 |
| Transformation Connection | 50 | 48 | 45 | 43 | 33 | 43 | 35 | 36 | 39 | 43 | 56 | 49 |
| | | | | | | | | | | | | |
| **2023** | | | | | | | | | | | | |
| Network Connection | 304 | 303 | 275 | 246 | 245 | 225 | 232 | 260 | 224 | 225 | 263 | 257 |
| Line Connection | 217 | 205 | 223 | 226 | 198 | 218 | 207 | 222 | 177 | 189 | 206 | 221 |
| Transformation Connection | 50 | 49 | 47 | 46 | 45 | 45 | 38 | 37 | 33 | 36 | 47 | 49 |
| | | | | | | | | | | | | |
| **2024** | | | | | | | | | | | | |
| Network Connection | 281 | 284 | 293 | 254 | 238 | 209 | 227 | 239 | 253 | 276 | 312 | 299 |
| Line Connection | 222 | 229 | 225 | 218 | 210 | 201 | 206 | 204 | 211 | 228 | 229 | 226 |
| Transformation Connection | 53 | 53 | 47 | 53 | 46 | 35 | 38 | 40 | 40 | 47 | 54 | 57 |
| | | | | | | | | | | | | |
| **2025** | | | | | | | | | | | | |
| Network Connection | 282 | 272 | 275 | 261 | 250 | 209 | 234 | 192 | 265 | 239 | 284 | 283 |
| Line Connection | 220 | 211 | 207 | 208 | 259 | 180 | 212 | 178 | 276 | 217 | 254 | 244 |
| Transformation Connection | 55 | 52 | 48 | 53 | 53 | 35 | 36 | 34 | 38 | 36 | 49 | 53 |

*Note: Charge determinant values are proxy numbers calculated based on actual data.*

# Appendix E – Forecast Accuracy

Tables 6a to 6c present the forecast accuracy of the OEB-approved forecasts of the three charge determinants on a weather-corrected basis for the past rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110).

All forecasts are weather-normal and compared with weather-corrected actuals. In all tables, a negative or positive percent deviation indicates that the forecast was below or above actual weather corrected.

**Table 6a**
**Historical Board Approved for Network Forecast**
**vs. Historical Actual and Historical Actual-Weather Normalized**

| | 12-Month Average in MW | | | | | | | | | | Difference from Actual Weather Corrected (%) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | EB-2006-0501 Forecast (1) | EB-2008-0272 Forecast (2) | EB-2010-0002 Forecast (3) | EB-2012-0031 Forecast (4) | EB-2014-0140 Forecast (5) | EB-2016-0160 Forecast (6) | EB-2019-0082 Forecast (7) | EB-2021-0110 Forecast (8) | Actual: Weather Corrected | Actual | EB-2006-0501 Forecast | EB-2008-0272 Forecast | EB-2010-0002 Forecast | EB-2012 0031 Forecast | EB-2014-0140 Forecast | EB-2016-0160 Forecast | EB-2019-0082 Forecast | EB-2021-0110 Forecast |
| 2005 | 21,704 | | | | | | | | 21,702 | 22,507 | 0.01 | | | | | | | |
| 2006 | 21,259 | | | | | | | | 21,275 | 22,028 | -0.08 | | | | | | | |
| 2007 | 20,827 | 20,928 | | | | | | | 20,928 | 22,398 | -0.48 | 0.00 | | | | | | |
| 2008 | 20,872 | 20,943 | | | | | | | 21,067 | 21,307 | -0.92 | -0.59 | | | | | | |
| 2009 | | 20,842 | 20,868 | | | | | | 20,868 | 20,410 | | -0.13 | 0.00 | | | | | |
| 2010 | | 20,199 | 20,414 | | | | | | 20,330 | 21,196 | | -0.64 | 0.41 | | | | | |
| 2011 | | | 20,150 | 20,245 | | | | | 20,245 | 20,861 | | | -0.47 | 0.00 | | | | |
| 2012 | | | 19,845 | 20,042 | | | | | 20,086 | 20,868 | | | -1.20 | -0.22 | | | | |
| 2013 | | | | 20,023 | 20,220 | | | | 20,220 | 21,352 | | | | -0.97 | 0.00 | | | |
| 2014 | | | | 19,552 | 20,276 | | | | 20,601 | 20,643 | | | | -5.09 | -1.58 | | | |
| 2015 | | | | | 20,559 | 20,236 | | | 20,236 | 20,384 | | | | | 1.60 | 0.00 | | |
| 2016 | | | | | 20,779 | 20,265 | | | 20,245 | 20,630 | | | | | 2.64 | 0.10 | | |
| 2017 | | | | | | 20,405 | | | 19,705 | 19,608 | | | | | | 3.55 | | |
| 2018 | | | | | | 20,410 | 19,678 | | 19,678 | 20,585 | | | | | | 3.72 | 0.00 | |
| 2019 | | | | | | | 19,614 | | 19,475 | 19,788 | | | | | | | 0.71 | |
| 2020 | | | | | | | 19,604 | 19,023 | 19,023 | 19,888 | | | | | | | 3.06 | 0.00 |
| 2021 | | | | | | | | 19,075 | 19,328 | 20,006 | | | | | | | | -1.31 |
| 2022 | | | | | | | | 19,126 | 19,599 | 20,566 | | | | | | | | -2.41 |
| 2023 | | | | | | | | 19,399 | 20,043 | 20,880 | | | | | | | | -3.21 |
| 2024 | | | | | | | | 19,449 | 20,599 | 20,823 | | | | | | | | -5.58 |
| 2025 | | | | | | | | 19,204 | 20,656 | 21,580 | | | | | | | | -7.03 |
| Average Excluding First Year (Actual) (9) | | | | | | | | | | | -0.49 | -0.45 | -0.42 | -2.10 | 0.89 | 2.46 | 1.88 | -3.91 |

(1) Forecast: EB-2006-0501; Ex A; T14; S 3; P 19 of 20.
(2) Forecast: EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) Forecast: EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Forecast: EB-2012-0031; Ex A; T15; S 2; P 22 of 24.
(5) Forecast: EB-2014-0140; Ex A; T15; S 2; P 20 of 23, settlement amount shown.
(6) Forecast: EB-2016-0160; Ex E1; T3; S 1; P 20 of 52.
(7) Forecast: EB-2019-0082; Ex E; T3; S 1; P 21 of 57, settlement amount shown.
(8) Forecast: EB-2021-0110; Ex E; T3; S 1; P 18 of 51, settlement amount shown.
(9) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110 forecast).

**Table 6b**
**Historical Board Approved for Line Connection Forecast**
**vs. Historical Actual and Historical Actual-Weather Normalized**

| | 12-Month Average in MW | | | | | | | | | | Difference from Actual Weather Corrected (%) (5) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | EB-2006-0501 Forecast (1) | EB-2008-0272 Forecast (2) | EB-2010-0002 Forecast (3) | EB-2012-0031 Forecast (4) | EB-2014-0140 Forecast (5) | EB-2016-0160 Forecast (6) | EB-2019-0082 Forecast (7) | EB-2021-0110 Forecast (8) | Actual: Weather Corrected | Actual | EB-2006-0501 Forecast | EB-2008-0272 Forecast | EB-2010-0002 Forecast | EB-2012 0031 Forecast | EB-2014-0140 Forecast | EB-2016-0160 Forecast | EB-2019-0082 Forecast | EB-2021-0110 Forecast |
| 2005 | 20,590 | | | | | | | | 20,590 | 21,345 | 0.00 | | | | | | | |
| 2006 | 20,242 | | | | | | | | 20,282 | 20,991 | -0.20 | | | | | | | |
| 2007 | 19,875 | 20,044 | | | | | | | 20,044 | 21,443 | -0.84 | 0.00 | | | | | | |
| 2008 | 19,940 | 20,111 | | | | | | | 20,156 | 20,386 | -1.07 | -0.23 | | | | | | |
| 2009 | | 20,100 | 19,796 | | | | | | 19,796 | 19,372 | | 1.53 | 0.00 | | | | | |
| 2010 | | 19,555 | 19,674 | | | | | | 19,348 | 20,162 | | 1.07 | 1.69 | | | | | |
| 2011 | | | 19,500 | 19,417 | | | | | 19,417 | 20,004 | | | 0.42 | 0.00 | | | | |
| 2012 | | | 19,286 | 19,359 | | | | | 19,298 | 20,047 | | | -0.06 | 0.32 | | | | |
| 2013 | | | | 19,406 | 19,322 | | | | 19,322 | 20,405 | | | | 0.44 | 0.00 | | | |
| 2014 | | | | 18,990 | 19,488 | | | | 19,626 | 19,843 | | | | -3.24 | -0.70 | | | |
| 2015 | | | | | 19,851 | 19,576 | | | 19,576 | 19,829 | | | | | 1.40 | 0.00 | | |
| 2016 | | | | | 20,150 | 19,605 | | | 19,540 | 20,027 | | | | | 3.12 | 0.33 | | |
| 2017 | | | | | | 19,741 | | | 19,100 | 19,064 | | | | | | 3.35 | | |
| 2018 | | | | | | 19,746 | 19,137 | | 19,137 | 20,040 | | | | | | 3.18 | 0.00 | |
| 2019 | | | | | | | 19,078 | | 18,880 | 19,180 | | | | | | | 1.05 | |
| 2020 | | | | | | | 19,071 | 18,435 | 18,435 | 19,274 | | | | | | | 3.45 | 0.00 |
| 2021 | | | | | | | | 18,502 | 18,773 | 19,429 | | | | | | | | -1.44 |
| 2022 | | | | | | | | 18,567 | 19,073 | 20,011 | | | | | | | | -2.66 |
| 2023 | | | | | | | | 18,830 | 19,426 | 20,226 | | | | | | | | -3.07 |
| 2024 | | | | | | | | 18,879 | 20,028 | 20,244 | | | | | | | | -5.74 |
| 2025 | | | | | | | | 18,642 | 20,322 | 21,228 | | | | | | | | -8.27 |
| Average Excluding First Year (Actual) (9) | | | | | | | | | | | -0.71 | 0.79 | 0.68 | -0.83 | 1.27 | 1.84 | 2.25 | -4.23 |

(1) Forecast: EB-2006-0501; Ex A; T14; S 3; P 19 of 20.
(2) Forecast: EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) Forecast: EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Forecast: EB-2012-0031; Ex A; T15; S 2; P 22 of 24.
(5) Forecast: EB-2014-0140; Ex A; T15; S 2; P 20 of 23, settlement amount shown.
(6) Forecast: EB-2016-0160; Ex E1; T3; S 1; P 20 of 52.
(7) Forecast: EB-2019-0082; Ex E; T3; S 1; P 21 of 57, settlement amount shown.
(8) Forecast: EB-2021-0110; Ex E; T3; S 1; P 18 of 51, settlement amount shown.
(9) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110 forecast).

**Table 6c**
**Historical Board Approved for Transformation Connection Forecast**
**vs. Historical Actual and Historical Actual-Weather Corrected**

| | 12-Month Average in MW | | | | | | | | | | Difference from Actual Weather Corrected (%) (5) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | EB-2006-0501 Forecast (1) | EB-2008-0272 Forecast (2) | EB-2010-0002 Forecast (3) | EB-2012-0031 Forecast (4) | EB-2014-0140 Forecast (5) | EB-2016-0160 Forecast (6) | EB-2019-0082 Forecast (7) | EB-2021-0110 Forecast (8) | Actual: Weather Corrected | Actual | EB-2006-0501 Forecast | EB-2008-0272 Forecast | EB-2010-0002 Forecast | EB-2012 0031 Forecast | EB-2014-0140 Forecast | EB-2016-0160 Forecast | EB-2019-0082 Forecast | EB-2021-0110 Forecast |
| 2005 | 17,702 | | | | | | | | 17,701 | 18,355 | 0.01 | | | | | | | |
| 2006 | 17,401 | | | | | | | | 17,419 | 18,031 | -0.10 | | | | | | | |
| 2007 | 17,086 | 17,329 | | | | | | | 17,329 | 18,537 | -1.40 | 0.00 | | | | | | |
| 2008 | 17,142 | 17,386 | | | | | | | 17,413 | 17,611 | -1.56 | -0.16 | | | | | | |
| 2009 | | 17,376 | 17,333 | | | | | | 17,333 | 16,999 | | 0.25 | 0.00 | | | | | |
| 2010 | | 16,905 | 16,999 | | | | | | 16,839 | 17,551 | | 0.39 | 0.95 | | | | | |
| 2011 | | | 16,850 | 16,769 | | | | | 16,769 | 17,274 | | | 0.48 | 0.00 | | | | |
| 2012 | | | 16,667 | 16,718 | | | | | 16,645 | 17,292 | | | 0.14 | 0.44 | | | | |
| 2013 | | | | 16,759 | 16,606 | | | | 16,606 | 17,536 | | | | 0.92 | 0.00 | | | |
| 2014 | | | | 16,400 | 16,748 | | | | 16,819 | 17,007 | | | | -2.49 | -0.42 | | | |
| 2015 | | | | | 17,060 | 16,731 | | | 16,731 | 16,952 | | | | | 1.96 | 0.00 | | |
| 2016 | | | | | 17,317 | 16,756 | | | 16,715 | 17,040 | | | | | 3.60 | 0.24 | | |
| 2017 | | | | | | 16,872 | | | 16,306 | 16,247 | | | | | | 3.47 | | |
| 2018 | | | | | | 16,876 | 16,329 | | 16,329 | 17,151 | | | | | | 3.35 | 0.00 | |
| 2019 | | | | | | | 16,258 | | 16,111 | 16,371 | | | | | | | 0.91 | |
| 2020 | | | | | | | 16,252 | 15,682 | 15,682 | 16,400 | | | | | | | 3.63 | 0.00 |
| 2021 | | | | | | | | 15,739 | 15,941 | 16,501 | | | | | | | | -1.27 |
| 2022 | | | | | | | | 15,794 | 16,169 | 16,966 | | | | | | | | -2.32 |
| 2023 | | | | | | | | 16,018 | 16,373 | 17,049 | | | | | | | | -2.17 |
| 2024 | | | | | | | | 16,059 | 16,805 | 16,989 | | | | | | | | -4.44 |
| 2025 | | | | | | | | 15,858 | 16,868 | 17,626 | | | | | | | | -5.99 |
| Average Excluding First Year (Actual) (9) | | | | | | | | | | | -1.02 | 0.16 | 0.52 | -0.37 | 1.71 | 2.36 | 2.27 | -3.24 |

(1) Forecast: EB-2006-0501; Ex A; T14; S 3; P 19 of 20.
(2) Forecast: EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) Forecast: EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Forecast: EB-2012-0031; Ex A; T15; S 2; P 22 of 24.
(5) Forecast: EB-2014-0140; Ex A; T15; S 2; P 20 of 23, settlement amount shown.
(6) Forecast: EB-2016-0160; Ex E1; T3; S 1; P 20 of 52.
(7) Forecast: EB-2019-0082; Ex E; T3; S 1; P 21 of 57, settlement amount shown.
(8) Forecast: EB-2021-0110; Ex E; T3; S 1; P 18 of 51, settlement amount shown.
(9) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, EB-2019-0082, and EB-2021-0110 forecast).

1

## Appendix F - Comparison with IESO Forecast

IESO only forecasts Ontario peak demand and does not produce a forecast for transmission charge determinants. In this Appendix, a comparison between latest IESO 18-month forecast and corresponding Hydro One forecast of Ontario peak demand is discussed. The comparison is consistent with the latest information from the IESO.

Of the IESO's 18-month peak forecast period, 17 months starting in March 2026 coincides with Hydro One's forecast period. Over the latter period the difference between IESO and Hydro One forecasts averages to 715 MW. Sources of difference can be shown to be due to the following two factors.

1. Extreme (i.e., hot or cold) weather may occur on any weekday, or on weekends and holidays, where the non-weather-related load is low compared to other days. Due to reliability concerns, IESO assumes that extreme weather occurs on the day of highest demand (Wednesdays) only. In contrast, in forecasting load for rate setting purposes Hydro One needs to take account of all possibilities, such as the extreme weather occurring during a weekend. The difference between the two forecasts due to this factor is 650 MW over the March 2026 to July 2027 period.

2. IESO does not deduct demand response from its demand forecast but rather takes it into account as an additional resource (or supply) in balancing demand and supply. In contrast, Hydro One needs to forecast the load net of demand response because load used to set transmission rates decreases due to demand response. The impact of this factor on the load forecast is about 300 MW.

In short, the total difference between IESO and Hydro One forecasts due to the factors noted above is 950 MW (650 MW + 300 MW). Comparing the latter figure with the actual difference between the two forecasts (715 MW) reveals that Hydro One's forecast is actually higher by 235 MW (950 MW - 715 MW) compared to the IESO forecast over the

March 2026 to July 2027 period after adjusting for the methodological differences noted above so that they would be comparable.

## Appendix G – Year-over-Year Comparison of Load

The two tables provide a year-over-year comparison of weather-normalized load across historical years, bridge years (2026 and 2027), and test years for Hydro One and HOSSM, respectively.

**Table G1a**

**Comparison of Historical, Bridge-Year, and Test-Years Load Weather-Normalized - Hydro One**
**(12-month average peak in MW)**

| | | | Charge Determinants | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Ontario | | | | Line | | Transformation | |
| Year | Peak | % Change | Network | % Change | Connection | % Change | Connection | % Change |
| 2013 | 20,360 | 0.1 | 20,220 | 0.7 | 19,322 | 0.1 | 16,606 | -0.2 |
| 2014 | 20,554 | 1.0 | 20,601 | 1.9 | 19,626 | 1.6 | 16,819 | 1.3 |
| 2015 | 20,203 | -1.7 | 20,236 | -1.8 | 19,576 | -0.3 | 16,731 | -0.5 |
| 2016 | 20,274 | 0.4 | 20,245 | 0.0 | 19,540 | -0.2 | 16,715 | -0.1 |
| 2017 | 19,696 | -2.8 | 19,705 | -2.7 | 19,100 | -2.3 | 16,306 | -2.4 |
| 2018 | 19,657 | -0.2 | 19,678 | -0.1 | 19,137 | 0.2 | 16,329 | 0.1 |
| 2019 | 19,575 | -0.4 | 19,475 | -1.0 | 18,880 | -1.3 | 16,111 | -1.3 |
| 2020 | 19,219 | -1.8 | 19,023 | -2.3 | 18,435 | -2.4 | 15,682 | -2.7 |
| 2021 | 19,242 | 0.1 | 19,328 | 1.6 | 18,773 | 1.8 | 15,941 | 1.6 |
| 2022 | 19,412 | 0.9 | 19,599 | 1.4 | 19,073 | 1.6 | 16,169 | 1.4 |
| 2023 | 19,976 | 2.9 | 20,043 | 2.3 | 19,426 | 1.8 | 16,373 | 1.3 |
| 2024 | 20,439 | 2.3 | 20,599 | 2.8 | 20,028 | 3.1 | 16,805 | 2.6 |
| 2025 | 20,485 | 0.2 | 20,656 | 0.3 | 20,322 | 1.5 | 16,868 | 0.4 |
| 2026 | 20,534 | 0.2 | 20,706 | 0.2 | 20,411 | 0.4 | 16,942 | 0.4 |
| 2027 | 20,658 | 0.6 | 20,831 | 0.6 | 20,534 | 0.6 | 17,044 | 0.6 |
| 2028 | 20,800 | 0.7 | 20,975 | 0.7 | 20,666 | 0.6 | 17,153 | 0.6 |
| 2029 | 20,970 | 0.8 | 21,145 | 0.8 | 20,828 | 0.8 | 17,288 | 0.8 |
| 2030 | 21,251 | 1.3 | 21,429 | 1.3 | 21,098 | 1.3 | 17,512 | 1.3 |
| 2031 | 21,586 | 1.6 | 21,766 | 1.6 | 21,414 | 1.5 | 17,774 | 1.5 |
| 2032 | 21,949 | 1.7 | 22,133 | 1.7 | 21,756 | 1.6 | 18,058 | 1.6 |

**Table G1b**

**Comparison of Historical, Bridge-Year, and Test-Years Load Weather-Normalized - HOSSM***
**(12-month average peak in MW)**

| | | | Charge Determinants | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Ontario | | | | Line | | Transformation | |
| Year | Peak | % Change | Network | % Change | Connection | % Change | Connection | % Change |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2013 | 20,360 | 0.1 | 260 | 0.7 | 204 | -1.8 | 50 | -0.2 |
| 2014 | 20,554 | 1.0 | 280 | 7.9 | 212 | 3.8 | 37 | -25.8 |
| 2015 | 20,203 | -1.7 | 264 | -6.0 | 214 | 0.7 | 39 | 5.1 |
| 2016 | 20,274 | 0.4 | 264 | 0.1 | 203 | -4.9 | 41 | 5.2 |
| 2017 | 19,696 | -2.8 | 259 | -1.8 | 210 | 3.6 | 36 | -10.6 |
| 2018 | 19,657 | -0.2 | 259 | 0.0 | 206 | -2.1 | 38 | 3.8 |
| 2019 | 19,575 | -0.4 | 255 | -1.7 | 207 | 0.5 | 40 | 5.6 |
| 2020 | 19,219 | -1.8 | 220 | -13.6 | 197 | -5.0 | 39 | -1.0 |
| 2021 | 19,242 | 0.1 | 251 | 14.2 | 209 | 6.5 | 42 | 5.7 |
| 2022 | 19,412 | 0.9 | 254 | 1.0 | 205 | -2.0 | 43 | 3.7 |
| 2023 | 19,976 | 2.9 | 255 | 0.5 | 209 | 1.9 | 44 | 0.6 |
| 2024 | 20,439 | 2.3 | 264 | 3.5 | 217 | 3.9 | 47 | 7.5 |
| 2025 | 20,485 | 0.2 | 254 | -3.8 | 222 | 2.2 | 45 | -3.8 |
| 2026 | 20,534 | 0.2 | 254 | 0.2 | 223 | 0.4 | 45 | 0.4 |
| 2027 | 20,658 | 0.6 | 256 | 0.6 | 225 | 0.6 | 46 | 0.6 |
| 2028 | 20,800 | 0.7 | 258 | 0.7 | 226 | 0.6 | 46 | 0.6 |
| 2029 | 20,970 | 0.8 | 260 | 0.8 | 228 | 0.8 | 46 | 0.8 |
| 2030 | 21,251 | 1.3 | 263 | 1.3 | 231 | 1.3 | 47 | 1.3 |
| 2031 | 21,586 | 1.6 | 267 | 1.6 | 234 | 1.5 | 47 | 1.5 |
| 2032 | 21,949 | 1.7 | 272 | 1.7 | 238 | 1.6 | 48 | 1.6 |

** Historical data includes Great Lakes Power prior to acquisition.*

# DATA FOR HYDRO ONE TRANSMISSION LOAD FORECAST

This attachment has been filed separately in MS Excel format

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# DISTRIBUTION LOAD FORECAST AND METHODOLOGY

## 1.0 INTRODUCTION

This Exhibit discusses Hydro One Distribution's load forecast and the related methodology.

The load forecast provides information on total distribution load and number of customers by rate class, which is used for the purpose of setting distribution rates. The load forecast in support of this Application was prepared in April 2026 using the available economic and forecast information.

Hydro One Distribution uses a number of methods, drawing on econometric and end-use approaches, and customer forecast surveys to produce the forecasts required for its distribution business. Similar methods are used by major utilities throughout North America.

All forecasts presented in this Exhibit are weather-normal, and the numbers are at the wholesale level unless otherwise specified. Abnormal weather effects are removed from the base year (2025) for load forecasting purposes, so that the forecast assumes typical weather conditions based on the average of the last 31 years. The weather correction methodology used by Hydro One Distribution is a proven technique that has performed well over the years. The same methodology was reviewed and approved by the OEB in the Distribution Cost Allocation Review (EB-2005-0317) and for Hydro One's previous distribution rate cases (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, EB-2013-0416, EB-2017-0049, and EB-2021-0110).

All forecasts are internally consistent, such that the load and number of customers for all customer classes add up to the total customer base served by Hydro One Distribution.

Exhibit D-03-01 discusses in detail the various economic inputs taken into consideration when applying the methodology for deriving the load forecasts. The actual load is presented in Exhibit D-05-01-01. The OEB's Appendix 2-IB is provided in Exhibit D-05-01-02, and Exhibit D-05-01-03 presents the derivation of the billing peak forecast from the sales forecast.

Witness: Bijan Alagheband

Hydro One Distribution's forecasting methodology comprises a combination of elements that include consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and the load impact of conservation and demand management (CDM) including energy efficiency and codes and standards. Economic inputs are based on analyses prepared by major economic institutions in the country, such as all major banks, Signal49 Research (formerly the Conference Board of Canada), and Stokes Economics (formerly the Centre for Spatial Economics or C4SE). Inputs from these institutions form the economic database (hereinafter, the "economic forecast") that is used to establish Hydro One Distribution's load forecast.

Using Hydro One Distribution's previously approved forecasting methodology, with a refined end-use analysis to account for current and available information, the forecast for the period 2026 to 2032 is presented in Table 1 below. The figures for 2031 and 2032 reflect the impact of integrating load and customer numbers of Orillia and Peterborough into Hydro One Distribution.

**Table 1 - Hydro One Distribution Load and Number of Customers**

| | Distribution | Distribution |
|---|---|---|
| Year | Load in GWh | Customer Count |
| 2026 | 41,002 | 1,471,687 |
| 2027 | 41,027 | 1,480,206 |
| 2028 | 41,372 | 1,490,079 |
| 2029 | 42,031 | 1,500,938 |
| 2030 | 42,675 | 1,511,705 |
| 2031* | 43,875 | 1,577,885 |
| 2032* | 44,520 | 1,588,896 |

*Note. All load figures are weather-normal.*
** Includes the impact of integrating Orillia and Peterborough into Hydro One Distribution.*

## 2.0 Economic Considerations That Influence the Distribution Load Forecast

This section discusses the key economic considerations in developing load forecasts and the application of forecasting methodologies. The elements of the forecasting process used by Hydro One Distribution are based on the relationship between major economic drivers and electricity demand over the forecast period 2026 to 2032. In addition, load research and end-use analyses are conducted to support the assessment of emerging electrification impacts, changes in customer electricity consumption patterns and behaviour, and the reasonableness of forecast load trends. Consequently, the load forecast will reflect the impact of such drivers on load. The major economic drivers used in the analysis are summarized in Figure 1.

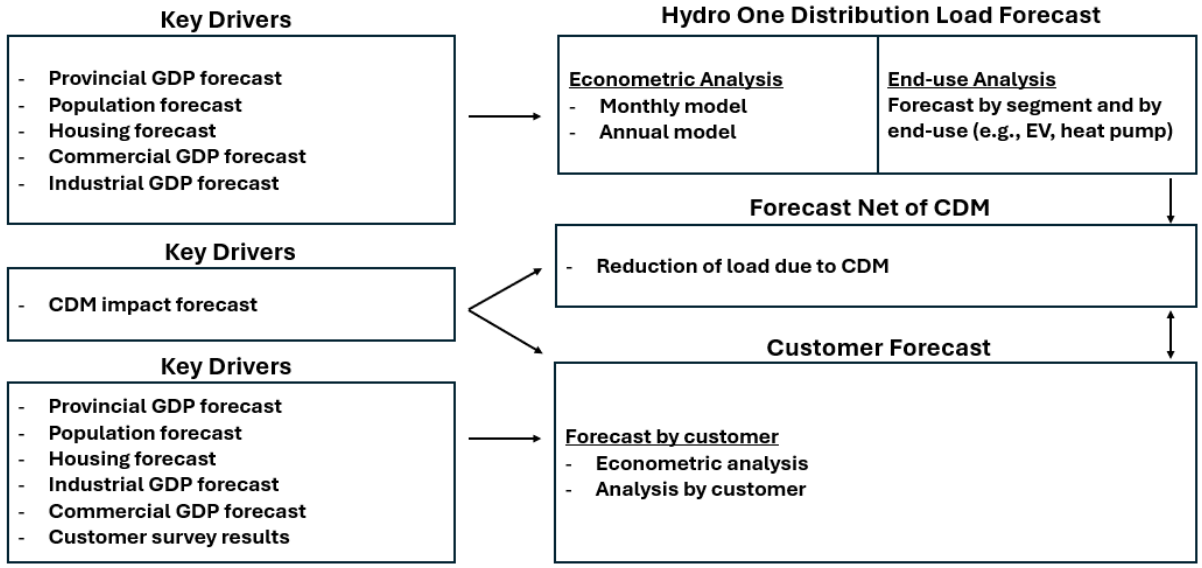



**Figure 1: Factors Affecting Distribution Load Forecast**

Key information used in the analysis includes Ontario GDP, provincial demographics, industrial GDP and commercial GDP forecasts, and regional analysis included in the economic forecast. Also taken into consideration is CDM, which has a direct impact on distribution system electricity demand.

The load forecast in support of this Application is based on the latest economic information and forecasts that were available in April 2026. The load forecast also takes into account 2025 actual load and CDM information consistent with the 2026 IESO Annual Planning Outlook (APO). Economic and demographic factors affecting the distribution load forecast are discussed in Exhibit D-03-01.

## 2.1 CONSERVATION AND DEMAND MANAGEMENT

Table 2 summarizes the CDM impact assumed in Hydro One's distribution system load forecast. Details of the CDM forecast by rate class are provided in Appendix E to this Exhibit, Table E.8.

**Table 2 - CDM Impact on Hydro One Distribution Load (GWh)**

| | Retail | ST Customers | | |
|---|---|---|---|---|
| Year | Customers | Direct | LDC | Total |
| 2024 | 3,389 | 432 | 1,553 | 5,374 |
| 2025 | 3,606 | 460 | 1,653 | 5,719 |
| 2026 | 3,782 | 482 | 1,733 | 5,998 |
| 2027 | 3,954 | 504 | 1,812 | 6,270 |
| 2028 | 4,110 | 524 | 1,884 | 6,518 |
| 2029 | 4,259 | 543 | 1,952 | 6,753 |
| 2030 | 4,396 | 561 | 2,014 | 6,970 |
| 2031* | 4,733 | 572 | 1,915 | 7,220 |
| 2032* | 4,798 | 580 | 1,942 | 7,320 |

*Note. All figures are weather-normal.*
** Includes the impact of integrating Orillia and Peterborough into Hydro One Distribution.*

The CDM figures for all years are consistent with the IESO's 2026 APO. The methodology for incorporating CDM into the load forecast is described in Section 3 of this Exhibit.

## 2.2 CUSTOMER FORECAST

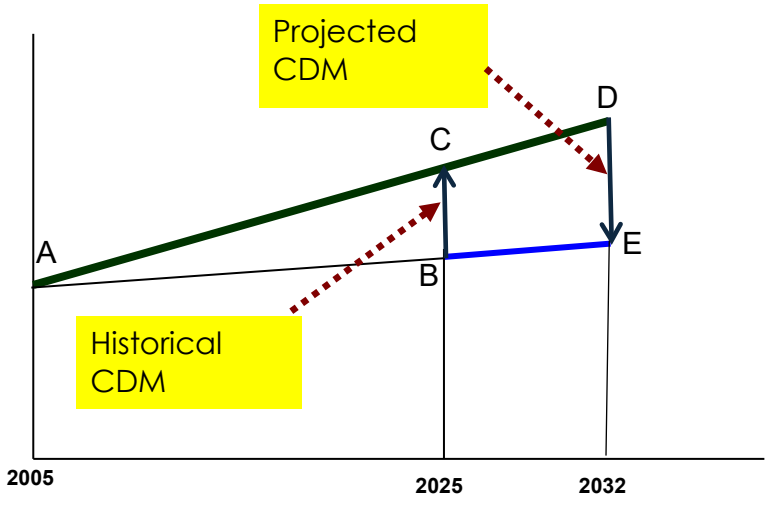
Hydro One's distribution system served about 1.431 million customers in 2023, 1.451 million customers in 2024, and 1.461 million in 2025. The customer base is forecast to increase from 1.472 million in 2026 to 1.512 million in 2030. With the integration of Orillia and Peterborough, the customer base is forecast to increase to 1.578 million in 2031, and 1.589 million in 2032.

Detailed customer information is retained in the billing and account management information systems. Customer data is extracted from the systems regularly for tracking, analysis and reporting. The customer forecast takes into consideration new customers requiring distribution services, existing customers moving out, provincial housing demand, population and household forecasts, vacancy rates and specific growth patterns of various customer groups.

Customer growth in Hydro One Distribution was about 10,000 in 2025, which is consistent with the economic conditions during that period. Customer growth for the forecast period, excluding Orillia and Peterborough, is expected to remain at about the same level. In addition, starting in 2031 about 55,000 customers from Orillia and Peterborough are added to the customer forecast. Details of the customer forecast by rate class over the forecast period are provided in Appendix E to this Exhibit, Table E.3.

## 3.0 LOAD FORECASTING METHODOLOGY

Hydro One Distribution's load forecast is developed by correcting the base year (2025) for abnormal weather conditions, as explained below, and applying forecast growth rates to the normalized base year value. The load impacts of CDM are added back to the historical values during the modelling process (see Figure 2 below).




A: 2005 actual load

B: 2025 actual load

C: Estimated load without CDM impact in 2025

D: Projected load without CDM impact in 2032

E: Projected load with CDM impact in 2032

**Figure 2: Incorporation of CDM in the Load Forecast**

## 3.1 WEATHER CORRECTION ANALYSIS

Weather correction is a statistical process designed to remove the abnormal or extreme weather effects from the load data to yield average conditions that reflect the expected weather conditions experienced over 31 years for use in the forecast. It is essential that impacts of abnormal and extreme weather are removed before establishing the base year (2025) load data, from which the load forecast is developed. The volatility of abnormal or extreme weather conditions can adversely impact the ability to provide a consistent and meaningful forecast for load. Hourly load data and hourly weather data of various weather stations across the province are used in the analysis.

Hydro One Distribution's weather correction methodology was developed jointly by forecasting and meteorology staff of the former Ontario Hydro. This weather correction method has been used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One is a proven technique that has performed well over the years. The same methodology was reviewed and approved by the OEB in the Distribution Cost Allocation Review (EB-2005-0317) and in previous Hydro One Distribution rate applications (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, EB-2013-0416, EB-2017-0049, and EB-2021-0110). Normal weather data is based on the average weather conditions experienced over the last 31 years, consistent with the approach used by the IESO and weather specialists and authorities around the world including Environment Canada, National Oceanic and Atmospheric Administration (NOAA) in the United States, and the Met Office in England. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year (2025). Use of 30 years or more of observations to measure the average of series is also supported by the central limit theorem in statistics asserting that such average would have an approximate normal distribution regardless of the underlying distribution of the series itself. For example, t-distribution can be approximated by normal distribution for 30 or more observations in the sample.

Hydro One Distribution's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the

applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud opacity and humidity. The estimated weather effects are then aggregated up to the required time interval. Experience shows that weather correction should best be done on a daily basis, rather than on a weekly, monthly or annually. Daily weather-correction is preferred because the timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over a longer period. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than would be the case if the same weather conditions were spread out over a much longer period. The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings.

Across Ontario, the penetration rate of such loads varies widely, which means the weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay, as such it is important to use data from the weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects.

## 3.2 DISTRIBUTION FORECASTING METHODOLOGY

Hydro One's distribution system load forecast is developed using a combination of complementary forecasting approaches, each described in the sections that follow. As set out in Exhibit D-03-01, key information used in the analysis includes economic data, demographics, industrial GDP and commercial GDP, based on economic forecast. The purpose of using these complementary approaches is to arrive at a balanced forecast that is consistent from both a macro and a micro perspective. This forecasting methodology was reviewed and approved by the OEB in the Distribution Cost Allocation Review (EB-2005-0317) and in Hydro One's previous distribution rate cases (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, EB-2013-0416, EB-2017-0049, and EB-2021-0110), with a refined end-use analysis to account for current and available information.

**Monthly Econometric Model**

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the distribution system load. The model links monthly energy consumption to Ontario GDP and residential building permits. Appendix A to this Exhibit provides the detailed regression equations and definitions.

**Annual Econometric Model**

The annual econometric model uses personal disposable income per household, relative energy price, and cooling and heating degree days as inputs to the forecast. Appendix B to this Exhibit provides the detailed regression equations and definitions.

**End-Use Analysis**

Traditionally, the end-use analysis covers the residential, commercial, industrial, and agricultural sectors. As in the case of monthly and annual econometric models previously discussed, the resulting forecast is gross of the load impact of CDM.

However, there has been a growing difficulty in updating the end-use models due to lack of detailed information required for doing so. On the other hand, there has also been a growing interest amongst system planners about end-use information related to certain items such as electric vehicles (EVs) and electric space heating. The general tendency amongst load forecasting institutions (e.g., IESO, Hydro One, Electric Power Research Institute (EPRI), etc.) has been to reduce reliance on the traditional end-use forecasting in favour of less granular forecasting methods that would be practical. Following this general trend and methodology used by EPRI, which originated in the European Union, and the Trottier Institute within McGill University in Canada, Hydro One uses an approach to end-use analysis that encompasses specific categories as described in Appendix C to this Exhibit.

The above forecasting approaches are used to prepare forecasts for the following 18 rate classes:

- Urban residential, high density
- R1 Residential, medium density

- R2 Residential, low density
- Urban general service, energy-billed
- Urban general service, demand-billed
- General service, energy-billed
- General service, demand-billed
- Sub-transmission
- Street lighting
- Sentinel lighting
- Unmetered scatter load
- Distributed generation
- Acquired mixed density residential
- Acquired mixed density general service – energy billed
- Acquired mixed density general service – demand billed
- Acquired urban density residential
- Acquired urban density general service – energy billed
- Acquired urban density general service – demand billed
- In addition, forecasts for Orillia and Peterborough by rate class were developed for the years 2031 and 2032

All forecasts by rate class are presented in Appendix E, Tables E3, E5, E6, E7a and E7b.

## 3.3 METHODOLOGY FOR SUB-TRANSMISSION CUSTOMERS

This section discusses the load forecasting methodology used for Sub-Transmission (ST) customers. ST customers include embedded distribution utilities, or large industrial and commercial customers. Both econometric and customer analysis based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

In 2026, Hydro One Distribution conducted a customer load forecast survey with the embedded distribution utilities and embedded industrial customers with more than 5 MW of loads. In addition to questions relating to the total load of the customer, information at each of

the delivery points was also collected. The customer survey results are used in preparing the customer forecast.

For embedded distribution utilities customers, an annual econometric model is used to prepare the load forecast as a group. The model uses the number of households, energy prices and cooling degree days to prepare the forecast.

For large industrial and commercial customers, several information sources are used to prepare the forecast. These include:

- historical load profile of the customer;
- knowledge of the customer through industry monitoring;
- forecast provided by customer through the survey;
- company information through Hydro One Distribution account executives, industry and company forecasts from industry associations and government agencies; and
- production and industry forecasts, which are provided in the economic forecast.

The econometric approach is used to forecast the load for embedded distribution utilities customers and industrial analysis is used to forecast the load for large industrial and commercial customers. In both cases, results from the customer survey are taken into account in developing the forecast.

## 3.4 METHODOLOGY FOR HOURLY LOAD PROFILES

This section discusses the methodology for generating the hourly load profiles by rate class.

Hourly Load Shape by Rate Class

EPRI's Hourly Electric Load Model (HELM) was used to develop the weather-normal hourly load shape for each rate class, taking out abnormal weather effects and load patterns. The load shapes vary by season, day-type, and temperature levels so that they cannot be represented by an equation. Actual 2025 hourly smart meter data from the IESO and interval meter data from Hydro One's customer information system were used as a basis to develop the weather-normal hourly load shapes. For rate classes for which hourly data was not

available for all customers, the hourly data was scaled to add up to the actual load for that rate class. The hourly forecast for each rate class also adds up to annual forecast for that rate class. Consequently, the forecast takes into account the share of each rate class in the total load and its dynamics over time. The load profiles for the years 2028 and 2031 take into account reclassification of some customers between rate classes in accordance with the annual forecast and are provided in Exhibit L-01-03 Attachment 7. Appendix D in this Exhibit provides more details for the methodology used by Hydro One to weather-normalize the total utility load and for each rate class.

## 4.0 LOAD FORECAST FOR 2026-2032

Hydro One's distribution system delivered a total of 40,459 GWh in 2024 and 40,997 GWh in 2025 on a weather-normal basis. Table 3 presents the load forecast before and after deducting the impact of CDM.

Before deducting the impact of CDM, Hydro One's distribution system is forecast to deliver 47,000 GWh in 2026 and 47,297 GWh in 2027. Load before deducting the CDM impacts over the years 2028 to 2032 is expected to continue to grow with the load forecast reaching 47,891 GWh, 48,785 GWh, 49,645 GWh, 51,095 GWh, and 51,841 GWh, respectively, on a weather-normal basis. The forecast reflects the continuation of economic recovery from the tariff issues as well as the impact of integrating Orillia and Peterborough into Hydro One Distribution in 2031.

Hydro One Distribution served about 1.451 million customers in 2024 and 1.461 million customers in 2025. Hydro One Distribution is forecast to serve about 1.472 million customers in 2026 and 1.480 million in 2027. The customer numbers are forecast to be 1.490 million, 1.501 million, 1.512 million, 1.578 million, and 1.589 million respectively over the 2028 to 2032 test period. The figures for 2031 and 2032 include the impact of integrating Orillia and Peterborough into Hydro One Distribution in 2031.

After applying the impact of CDM, Hydro One Distribution's load increases from 40,459 GWh in 2024 to 40,997 GWh in 2025 and is forecast to be 41,002 GWh in 2026 and 41,027 GWh in 2027, on a weather-normalized basis. Over the years 2028 to 2032, the weather-normalized

total distribution load is forecast to be 41,372 GWh, 42,031 GWh, 42,675 GWh, 43,875 GWh, and 44,520 GWh, respectively. Detailed tables for actual and weather-normalized total load, energy and peak by rate class are provided in Appendix E to this Exhibit, Tables E.5 to E.7a and E7b. The peak forecast for each rate class is derived from corresponding sales forecast using load factor. Results by rate class in Appendix E to this Exhibit reflect changes due to rate class boundary review (as approved by the OEB in EB-2013-0416) and continuation of these changes over the years 2026 to 2032 as discussed in Exhibit L-01-02.

**Table 3 - Hydro One Distribution Load Forecast Before and After Deducting CDM Impact (GWh)**

| Year | Retail Customers | Embedded Customers | Total |
|---|---|---|---|
| **Load Forecast Before Deducting Impact of CDM** | | | |
| 2024 | 26,906 | 18,926 | 45,833 |
| 2025 | 27,146 | 19,570 | 46,716 |
| 2026 | 27,306 | 19,694 | 47,000 |
| 2027 | 27,410 | 19,888 | 47,297 |
| 2028 | 27,754 | 20,136 | 47,891 |
| 2029 | 28,344 | 20,441 | 48,785 |
| 2030 | 28,912 | 20,733 | 49,645 |
| 2031* | 30,901 | 20,194 | 51,095 |
| 2032* | 31,410 | 20,430 | 51,841 |
| **Load Impact of CDM** | | | |
| 2024 | 3,389 | 1,985 | 5,374 |
| 2025 | 3,606 | 2,113 | 5,719 |
| 2026 | 3,782 | 2,216 | 5,998 |
| 2027 | 3,954 | 2,317 | 6,270 |
| 2028 | 4,110 | 2,408 | 6,518 |
| 2029 | 4,259 | 2,495 | 6,753 |
| 2030 | 4,396 | 2,575 | 6,970 |
| 2031* | 4,733 | 2,488 | 7,220 |
| 2032* | 4,798 | 2,522 | 7,320 |
| **Load Forecast After Deducting Impact of CDM** | | | |
| 2024 | 23,518 | 16,941 | 40,459 |
| 2025 | 23,539 | 17,457 | 40,997 |
| 2026 | 23,524 | 17,478 | 41,002 |
| 2027 | 23,456 | 17,571 | 41,027 |
| 2028 | 23,644 | 17,728 | 41,372 |
| 2029 | 24,085 | 17,946 | 42,031 |
| 2030 | 24,517 | 18,158 | 42,675 |
| 2031* | 26,168 | 17,706 | 43,875 |
| 2032* | 26,612 | 17,908 | 44,520 |

*Note. All load figures are weather-normal.*
** Includes the impact of integrating Orillia and Peterborough into Hydro One Distribution.*

Since the forecast is weather-normal, the actual load could be below or above the forecast depending on the weather conditions and/or a different economic/demographic growth pattern. Table 4 presents the upper and lower bands of one standard deviation for the Hydro One Distribution system load forecast. Based on historical data, there is a two-in-three chance that the actual load over the forecast years (2026-2032) will fall within the upper and lower bands. The bands are derived using a Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.

**Table 4 - One Standard Deviation Uncertainty Bands for Hydro One Distribution Load (GWh)**

| Year | Lower Bound | Forecast | Upper Bound |
|---|---|---|---|
| 2025 | 40,997 | 40,997 | 40,997 |
| 2026 | 40,196 | 41,002 | 41,798 |
| 2027 | 40,000 | 41,027 | 42,062 |
| 2028 | 40,180 | 41,372 | 42,567 |
| 2029 | 40,522 | 42,031 | 43,533 |
| 2030 | 40,863 | 42,675 | 44,518 |
| 2031* | 41,627 | 43,875 | 46,162 |
| 2032* | 41,779 | 44,520 | 47,311 |

** Includes the impact of integrating Orillia and Peterborough into Hydro One Distribution.*

## Appendix A – Monthly Econometric Model

The monthly econometric model uses the State-Space (SS) approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that could affect the energy estimates because these events would likely cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LRTLT = f (LGDPONT, LBPONT, D98Jan)

where:

LRTLT = logarithm of retail load,

LGDPONT = logarithm of Ontario GDP in constant 2017 dollars,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance
- Forecast is based on annual consensus forecast for Ontario GDP as presented in Appendix A of Exhibit D-03-01

LBPONT = logarithm of Ontario residential building permits in constant dollar,

- History is based on monthly value of Ontario residential building permits from Statistics Canada
- Forecast is based on consensus forecast of housing starts as presented in Appendix A of Exhibit D-03-01

D98Jan = dummy variable to account for the load impact of 1998 Ice Storm, equals 1 in January 1998 and zero elsewhere,

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

| | State-Space (SS) |
|---|---|
| Seasonal Factors | parameters: |
| A[1] | -0.141496 |
| K[1] | -0.551217 |
| Non-Seasonal Factors | SS parameters: |
| A[1] | 0.511985 |
| K[1] | -0.369139 |
| GDPONT[-4] | 0.0624706 |
| BPONT[-8] | 0.00488659 |
| D98JAN | -0.014388 |

R-squared = 0.987, R-squared corrected for mean = 0.987, Durbin-Watson Statistics = 2.24, Prob F = 0.00.

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain the variations in load. This is also reflected in probability related F statistic, which is nearly 0. In fact, the results show that in this case the fit is very good, and therefore there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the above parameters are used in the monthly regression equation described on the previous page to generate the forecast for Hydro One Distribution load using the State-Space algorithm.

## Appendix B – Annual Econometric Model

In this Appendix, regression results for annual econometric models are presented.

Retail Load

Annual econometric model for retail load uses personal disposable income per household, relative energy price, and heating degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-4)-LPGASRES(-4))
+C(4)*LHDD+C(5)*LRTLT(-1)-C(4)*C(5)*LHDD(-1)+C(6)*D99A
+C(7)*(1/TR)+C(8)*D08ON+C(9)*DM

where:

LRTLT = logarithm of retail load,

LYPDPHH = logarithm of Ontario personal disposable income per household / number of households in constant dollar,

- History is based on disposable income in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistics Canada and divided by the number of households / houses based on Signal49 Research (formerly Conference Board of Canada) housing starts
- Forecast is based on forecasts of disposable income from Stokes Economics (formerly C4SE) and Signal49 Research deflated by CPI from Signal49 Research and divided by the number of household / houses based on consensus forecast of housing starts as presented in Exhibit D-03-01 Appendix A

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and Canada Energy Regulator (CER) 2026
- Forecast is from CER 2026 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026 Outlook
- Forecast is from CER 2026 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Toronto Pearson International Airport (Toronto),

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

D08ON = a dummy variable to account for economic changes, equals zero prior to 2008 and 1 elsewhere.

DM = a dummy variable to account for the impact of above-normal immigration targets on load, equals 1 from 2022 to 2025 and zero elsewhere.

C(1) – C(9) = variable coefficients.

The estimated model is presented below:

| | Estimated Coefficient | Standard Error | t-ratio | Prob. |
|---|---|---|---|---|
| C(1) | 0.489306 | 0.73015 | 0.670145 | 0.5068 |
| C(2) | 0.517059 | 0.086979 | 5.944626 | 0 |
| C(3) | -0.01244 | 0.010626 | -1.17055 | 0.2491 |
| C(4) | 0.108935 | 0.034246 | 3.180962 | 0.0029 |
| C(5) | 0.734712 | 0.065714 | 11.18049 | 0 |
| C(6) | -0.03224 | 0.008943 | -3.60451 | 0.0009 |
| C(7) | -4.08229 | 1.695766 | -2.40734 | 0.021 |
| C(8) | -0.03536 | 0.010779 | -3.28035 | 0.0022 |
| C(9) | 0.027311 | 0.013338 | 2.047688 | 0.0475 |

R-squared = 0.988, Adjusted R-squared = 0.985, Durbin-Watson Statistic = 1.88, Prob F =0.00

Like the regression analysis in the case of the Monthly Econometric model above, the goodness of fit, measured by (Adjusted) R-square for the Annual Econometric Model for retail load, is also found to be close to 1. This is also reflected in probability related F statistic, which is nearly 0.

The latter probability for T statistics for some estimated coefficient is marginally higher than 0, indicating a mild level of multicollinearity, which is a common characteristic of economic time series. Therefore, the assessment on an annual basis also leads to a forecast outcome which provides consistent results, thus giving confidence to the econometric method.

The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for personal disposable income per household / house, energy prices, and heating degree days and dummy variables, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Distribution load using the regression algorithm.

Embedded LDC Load

Annual econometric model for embedded LDC load uses the number of houses/households, relative energy price, and cooling degree days to prepare the forecast. The annual model is expressed in the following regression equation:

LEMBLDCS=C(1)+C(2)*D(LHHOLD)+C(3)*(LPELRES(-1)
-LPGASRES(-1))+C(4)*LCDD+C(5)*LHDD+C(6)*LEMBLDCS(-1)
-C(4)*C(6)*LCDD(-1)-C(5)*C(6)*LHDD(-1)+C(7)*(1/TR)

where:

LEMBLDCS = logarithm of Embedded LDC load,

LHHOLD = logarithm of Ontario number of households / houses,

- History from Signal49 Research housing starts
- Forecast is based on consensus forecast of housing starts as presented in Exhibit D-03-01 Appendix A

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026 Outlook

- Forecast is from CER 2026 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, S&P Global, 2013 LTEP and CER 2026
- Forecast is from CER 2026 Outlook accounting for carbon tax

LCDD = logarithm of cooling degree days for Toronto Pearson International Airport,

LHDD = logarithm of heating degree days for Toronto Pearson International Airport,

TR = a dummy variable to account for a shift in growth pattern of distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

C(1) – C(7) = variable coefficients.

The estimated model is presented below:

| | Estimated Coefficient | Standard Error | t-ratio | Prob. |
|---|---|---|---|---|
| C(1) | 1.686114 | 0.544352 | 3.097471 | 0.0036 |
| C(2) | 1.756206 | 0.91096 | 1.927863 | 0.061 |
| C(3) | -0.0339 | 0.01619 | -2.094 | 0.0426 |
| C(4) | 0.013264 | 0.010388 | 1.276884 | 0.209 |
| C(5) | 0.024201 | 0.057165 | 0.423357 | 0.6743 |
| C(6) | 0.826164 | 0.055098 | 14.99435 | 0 |
| C(7) | -56.225 | 22.83982 | -2.46171 | 0.0182 |

R-squared = 0.967, Adjusted R-squared = 0.962, Durbin-Watson Statistic = 2.21, Prob F =0.00

Like the regression analysis in the case of the other econometric models noted above, the goodness of fit, measured by (Adjusted) R-square for the Embedded LDC Model, is also found to be close to 1 leading to a forecast outcome which provides consistent results, thus giving confidence to the econometric method. This is also reflected in probability related F statistic, which is nearly 0. The latter probability for T statistics for some estimated coefficient is marginally higher than 0, indicating a mild level of multicollinearity, which is a common characteristic of economic time series. The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Witness: Bijan Alagheband

Using the forecast values for Ontario number of households / houses, energy prices, and cooling degree days and dummy variable, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Embedded LDC load using regression algorithm.

## Appendix C – Load Research and Next Generation (NG) End-Use Analysis

Hydro One maintains a comprehensive load research and end-use analysis program to support load forecasting, system planning, customer program development, and investment decision-making. These activities provide insights into electricity consumption patterns, technology adoption, fuel choices, electrification trends, and evolving customer behaviour across Hydro One's service territory.

Hydro One's load research program includes annual residential equipment surveys, industrial customer monitoring and surveys, fuel-switching studies, EV adoption analysis, and other targeted end-use research activities. In addition, Hydro One performs disaggregated end-use analysis based on customer Meter Data Management and Repository (MDMR) interval data and billing information to develop a more granular understanding of electricity consumption behaviour, end-use trends, load characteristics, and electrification impacts. The resulting information is used to support the development, calibration, validation, and ongoing enhancement of Hydro One's forecasting methodologies.

Traditionally, end-use forecasting relied on detailed estimates of electricity consumption by individual appliances, equipment types, building characteristics, and industrial processes. Such approaches require extensive information regarding end-use penetration rates, utilization patterns, and unit energy consumption. While these methods continue to provide valuable insights for load research and customer analysis, the availability and quality of the information required to maintain highly granular end-use forecasting models has become increasingly challenging in the context of rapidly evolving technologies, electrification initiatives, climate policies, and changing customer preferences.

At the same time, there is growing interest among system planners and other stakeholders in understanding the load impacts associated with emerging electrification technologies and applications. Examples include EVs, heat pumps, electric space heating, electrification of transportation, electrification of industrial processes, and other technologies that may materially influence future electricity demand and load profiles. Accordingly, Hydro One has evolved its

forecasting framework by supplementing its traditional load research and end-use analysis activities with a Next Generation (NG) End-Use Analysis focused on key electrification drivers.

The objective of the NG End-Use Analysis is not to forecast each individual appliance or technology separately. Rather, the analysis is intended to provide a practical and robust assessment of the principal sources of future load growth arising from electrification. The analysis incorporates insights obtained through Hydro One's load research activities together with observed load trends, technology adoption patterns, market developments, customer information, and relevant government electrification and decarbonization initiatives.

For emerging technologies such as EVs and electric heating systems, adoption is expected to follow growth patterns commonly associated with the introduction and maturation of new technologies. Accordingly, the NG End-Use Analysis incorporates technology adoption trajectories informed by observed market developments, available customer information, and relevant electrification policies. The resulting estimates are periodically reviewed against observed load data and other available information to ensure continued reasonableness.

The NG End-Use Analysis is used as a supplementary forecasting tool to assess the impact of electrification on future electricity demand and customer behaviour. It provides additional insight into emerging load drivers that may not be fully reflected in historical trends alone. For example, the analysis supports Hydro One's assessment of service upgrade requirements, where recent experience indicates that technologies such as EV chargers and heat pumps are contributing to service upgrade activity beyond what would be expected based solely on growth in customer connections.

The results of the NG End-Use Analysis are considered alongside Hydro One's econometric forecasting methodologies in the development, interpretation, and validation of the load forecast. Collectively, Hydro One's load research program, disaggregated end-use analysis, NG End-Use Analysis, customer research initiatives, and econometric forecasting models provide a complementary framework for assessing future electricity demand and the potential impacts of electrification.

## Appendix D – Weather Normalization for Total Load and by Rate Class

Weather Normalization for Total Utility Load

Hydro One's weather normalization methodology for total utility load is summarized as follows:

- An equation relating daily energy to daily weather conditions is developed using the latest four years of data. This time frame allows the analysis to reflect the most recent load mix while having sufficient data to quantify its weather sensitivity. For example, the share of space cooling energy relative to total energy has increased rapidly over the past decade; using too long of a time series of historical data may lead to significant under-estimation of the weather sensitivity of load in the summer.
- To better isolate the impact of weather, systematic changes in daily loads are identified and filtered out before the regression analysis begins. The systematic effects which are removed include growth trends, cyclical variations, day-of-the-week effects and holiday effects. The objective is to filter the data to weather-related load and noise (random effect).
- Different types of weather data are used in the analysis. For winter loads, weather data include temperature, wind speed and cloud opacity. For summer loads, weather data include temperature, humidity and cloud opacity. Because weather effects accumulate over several days, the temperatures for the current day as well as the previous three or four days are also used as explanatory variables in the model. The relationship between energy and weather may be represented by the following function:

Weather-Related Energy = f (Weather Conditions) + Random Term

(1)

where the random term reflects any remaining variations that are not explained systematically by weather. The random term is assumed to be distributed independently, identically and normally with mean equals to zero.

- The coefficients from Equation (1) are estimated using the most recent four years of daily load and weather data. These coefficients indicate the sensitivity of load in the service territory relative to today's temperature, yesterday's temperature and all other weather variables included in the equation. The estimated coefficients are multiplied by the actual weather data for the corresponding weather variable in the equation to determine the estimated weather-related energy for the day. This process is repeated for each day of the period for which the weather-correction is performed.

Estimated Weather-Related Energy = f (Actual Weather Conditions and Estimated Coefficients)

(2)

- Equation (2) is used to determine what "normal" weather-related loads would be for each day of the year given the current mix of weather-sensitive loads in that service territory. This is done by running the equation with each of the last 31 years of daily weather data for that day plus the seven days on either side of it. The average of the estimated weather-related loads for the 15 days times 31 years (465 observations) is deemed to be the "normal" weather-related energy for that day. Using 31 years of weather history is considered adequate to approximate normal weather.

Normal Weather-Related Energy (for each day) = Average (31 years of Estimated Weather-Related Energy for that Day +/- 7 Days)

(3)

- On a daily basis, the weather correction is derived as the difference between the estimated and normal weather- related energy:

Weather Correction for Energy = Normal Weather-Related Energy – Estimated Weather-Related Energy

(4)

- Weather-corrected energy is defined to be actual energy plus the weather correction in any given period. For any period that is more than one day (e.g., a month), the total weather correction is the sum of the daily weather correction.

Weather-Corrected Energy = Actual Energy + Weather Correction for Energy

(5)

- For example, a summer day for which the combination of temperature and humidity are above normal yields a negative weather correction. The weather correction in this case should be viewed as the amount to be subtracted from the above normal actual to get the weather-corrected energy. Similarly, a warm winter day would have a positive weather correction as the weather corrected value for that day should be higher than the below normal actual.

<u>Weather Normalization by Rate Class</u>

Weather correction by rate class is derived from weather correction for the total utility using the electric space heating and cooling shares by rate class or segment as detailed below.

- Weather correction for the total load is discussed above using daily energy for the utility. The amount of weather correction is measured on a daily basis.
- Using average daily temperature for each day, the daily weather correction is grouped into “weather correction for space heating” and “weather correction for space cooling”. For example, if average daily temperature is less than 15 degrees Celsius, the weather correction for that day is allocated to “weather correction for space heating” load. The

daily weather correction results are aggregated into annual or monthly weather correction estimates.

- Using load shape analysis and residential appliance saturation estimates, the amount of space heating and cooling load over a year or month are estimated for each rate class. Next, for each rate class, the cooling and heating weather correction amount are calculated using the total cooling and heating weather correction amount multiplied by the corresponding cooling and heating shares. The weather-corrected load for each rate class is estimated by adding the weather correction estimates by rate class to the corresponding (actual) load for each rate class.

# Appendix E – Statistical Appendix

## Table E.1 - Economic Variables for Ontario

| Year | GDP (2017 M$) | % Change | Population (1,000's) | % Change | Housing (1,000's) | % Change |
|---|---|---|---|---|---|---|
| 2015 | 785,866 | 2.5 | 13,707 | 0.7 | 69.0 | 17.8 |
| 2016 | 802,365 | 2.1 | 13,875 | 1.2 | 74.7 | 8.3 |
| 2017 | 824,979 | 2.8 | 14,070 | 1.4 | 79.9 | 6.9 |
| 2018 | 852,029 | 3.3 | 14,309 | 1.7 | 79.1 | -1.0 |
| 2019 | 869,792 | 2.1 | 14,545 | 1.6 | 69.0 | -12.8 |
| 2020 | 830,265 | -4.5 | 14,762 | 1.5 | 81.3 | 17.9 |
| 2021 | 880,652 | 6.1 | 14,842 | 0.5 | 99.6 | 22.5 |
| 2022 | 919,450 | 4.4 | 15,156 | 2.1 | 96.1 | -3.5 |
| 2023 | 941,547 | 2.4 | 15,632 | 3.1 | 89.3 | -7.1 |
| 2024 | 956,996 | 1.6 | 16,145 | 3.3 | 74.6 | -16.5 |
| 2025 | 968,583 | 1.2 | 16,258 | 0.7 | 65.2 | -12.6 |
| 2026 | 978,112 | 1.0 | 16,202 | -0.3 | 63.8 | -2.1 |
| 2027 | 996,301 | 1.9 | 16,190 | -0.1 | 62.7 | -1.8 |
| 2028 | 1,018,119 | 2.2 | 16,264 | 0.5 | 74.7 | 19.1 |
| 2029 | 1,041,584 | 2.3 | 16,409 | 0.9 | 81.7 | 9.4 |
| 2030 | 1,060,332 | 1.8 | 16,557 | 0.9 | 79.9 | -2.2 |
| 2031 | 1,080,478 | 1.9 | 16,722 | 1.0 | 80.9 | 1.3 |
| 2032 | 1,099,927 | 1.8 | 16,889 | 1.0 | 79.8 | -1.3 |

# Table E.2 - Comparison of Forecasts for Previous Rate Submissions with Actual (GWh)

| Year | 2005 Forecast (EB-2005-0378) | 2007 Forecast (EB-2007-0681) | 2009 Forecast (EB-2009-0096) | 2013 Forecast EB-2013-0416 | 2018 * Forecast EB-2017-0049 | 2021 ** Forecast EB-2021-0110 | Weather Corrected Actual | Actual | % Difference from Weather Corrected Actual: 2005 Forecast | 2007 Forecast | 2009 Forecast | 2013 Forecast | 2018 * Forecast | 2021 ** Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 22,950 | | | | | | 22,969 | 23,182 | -0.08 | | | | | |
| 2006 | 23,074 | | | | | | 22,921 | 22,485 | 0.67 | | | | | |
| 2007 | | 22,945 | | | | | 22,966 | 22,909 | | -0.09 | | | | |
| 2008 | | 23,062 | | | | | 22,845 | 22,624 | | 0.95 | | | | |
| 2009 | | 23,029 | 22,629 | | | | 22,660 | 22,299 | | 1.62 | -0.14 | | | |
| 2010 | | | 22,007 | | | | 22,062 | 21,977 | | | -0.25 | | | |
| 2011 | | | 21,851 | | | | 22,023 | 21,718 | | | -0.78 | | | |
| 2012 | | | | | | | 20,434 | 19,964 | | | | | | |
| 2013 | | | | | | | 20,439 | 20,668 | | | | | | |
| 2014 | | | | 20,413 | | | 20,267 | 20,639 | | | | 0.72 | | |
| 2015 | | | | 20,497 | | | 20,203 | 20,343 | | | | 1.45 | | |
| 2016 | | | | 20,630 | | | 20,085 | 19,862 | | | | 2.71 | | |
| 2017 | | | | 20,808 | | | 19,664 | 19,443 | | | | 5.82 | | |
| 2018 | | | | | 19,372 | | 19,277 | 19,391 | | | | | 0.49 | |
| 2019 | | | | | 19,106 | | 19,207 | 20,476 | | | | | -0.52 | |
| 2020 | | | | | 19,006 | | 19,149 | 20,879 | | | | | -0.75 | |
| 2021 | | | | | | 19,158 | 19,228 | 21,402 | | | | | | -0.37 |
| 2022 | | | | | | 19,198 | 20,321 | 20,492 | | | | | | -5.53 |
| 2023 | | | | | | 20,273 | 20,876 | 20,304 | | | | | | -2.89 |
| 2024 | | | | | | 20,311 | 21,430 | 21,127 | | | | | | -5.22 |
| 2025 | | | | | | 20,040 | 21,170 | 21,518 | | | | | | -5.34 |
| Average | | | | | | | | | 0.29 | 0.83 | -0.39 | 2.68 | -0.26 | -3.87 |

* Represents Approved forecast for EB-2017-0049 presented in Exhibit I, Tab 46, Schedule Staff-219 based on using 2017 actual.
** Represents Approved forecast for EB-2021-0110.

## Table E.3 - Number of Customers History and Forecast

| Rate Class | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Generator | 1,158 | 1,156 | 1,247 | 1,243 | 1,312 | 1,381 | 1,451 | 1,521 | 1,591 | 1,661 | 1,731 | 1,800 |
| General Service - Demand Billed | 5,091 | 4,515 | 4,928 | 4,731 | 4,777 | 5,244 | 5,292 | 5,266 | 5,316 | 5,368 | 5,420 | 5,474 |
| General Service - Energy Billed | 80,659 | 81,316 | 91,652 | 92,901 | 93,093 | 92,347 | 92,479 | 91,463 | 91,632 | 91,821 | 92,028 | 92,255 |
| Residential - Medium Density | 482,413 | 492,489 | 559,340 | 567,050 | 571,773 | 571,099 | 575,064 | 565,794 | 570,741 | 575,638 | 580,561 | 585,428 |
| Residential - Low Density | 338,776 | 341,792 | 419,093 | 424,073 | 425,686 | 426,965 | 428,032 | 429,288 | 431,088 | 432,854 | 434,643 | 436,395 |
| Seasonal * | 140,165 | 138,378 | | | | | | | | | | |
| Sub-transmission | 879 | 881 | 1,117 | 1,161 | 1,170 | 1,180 | 1,190 | 1,200 | 1,211 | 1,222 | 1,232 | 1,243 |
| Urban General Service - Demand Billed | 1,592 | 1,440 | 1,585 | 1,520 | 1,530 | 1,717 | 1,729 | 1,816 | 1,828 | 1,841 | 1,854 | 1,867 |
| Urban General Service - Energy Billed | 17,036 | 16,998 | 18,247 | 18,586 | 18,702 | 19,070 | 19,179 | 20,460 | 20,577 | 20,698 | 20,822 | 20,951 |
| Urban Residential | 239,869 | 240,078 | 240,658 | 245,788 | 249,132 | 258,328 | 261,389 | 278,739 | 282,240 | 285,715 | 289,200 | 292,656 |
| Street Light | 5,409 | 5,745 | 6,081 | 6,432 | 6,482 | 6,529 | 6,569 | 6,614 | 6,664 | 6,714 | 6,764 | 6,813 |
| Sentinel Light | 19,862 | 19,439 | 19,723 | 19,383 | 19,052 | 18,731 | 18,382 | 18,054 | 17,732 | 17,414 | 17,101 | 16,792 |
| Unmetered Scattered Load | 5,644 | 5,669 | 5,753 | 5,782 | 5,824 | 5,866 | 5,902 | 5,943 | 5,988 | 6,032 | 6,077 | 6,122 |
| Acquired Residential | 39,411 | 40,200 | 40,200 | 40,774 | 41,063 | 41,351 | 41,589 | 41,864 | 42,166 | 42,464 | 42,765 | 43,061 |
| Acquired General Service - Energy Billed | 4,188 | 4,265 | 4,265 | 4,279 | 4,262 | 4,246 | 4,229 | 4,213 | 4,196 | 4,180 | 4,163 | 4,147 |
| Acquired General Service - Demand Billed | 332 | 254 | 254 | 240 | 232 | 233 | 235 | 237 | 239 | 241 | 243 | 244 |
| Acquired Urban Residential | 13,007 | 15,494 | 15,494 | 15,622 | 15,725 | 15,826 | 15,909 | 16,006 | 16,112 | 16,216 | 16,322 | 16,426 |
| Acquired Urban General Service - Energy Billed | 1,308 | 1,356 | 1,356 | 1,380 | 1,393 | 1,400 | 1,413 | 1,427 | 1,442 | 1,453 | 1,466 | 1,477 |
| Acquired Urban General Service - Demand Billed | 216 | 191 | 172 | 172 | 172 | 172 | 172 | 173 | 173 | 173 | 173 | 174 |
| Orillia - Residential | 12,673 | 12,791 | 12,882 | 13,589 | 13,607 | 13,689 | 13,757 | 13,835 | 13,921 | 14,006 | 14,092 | 14,177 |
| Orillia - General Service Energy-Billed | 1,422 | 1,446 | 1,456 | 1,538 | 1,546 | 1,551 | 1,558 | 1,566 | 1,575 | 1,581 | 1,588 | 1,595 |
| Orillia - General Service Demand-Billed | 168 | 170 | 171 | 134 | 134 | 135 | 136 | 136 | 136 | 136 | 126 | 126 |
| Orillia - Sub-transmission | | | | | | | | | | | 10 | 10 |
| Orillia - Street Light | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Orillia - Unmetered Scattered Load | 23 | 23 | 23 | 23 | 24 | 24 | 24 | 25 | 25 | 25 | 25 | 26 |
| Peterborough - Residential | 33,598 | 33,802 | 34,007 | 34,390 | 34,501 | 34,630 | 34,737 | 34,860 | 34,995 | 35,128 | 35,263 | 35,395 |
| Peterborough - General Service Energy-Billed | 3,461 | 3,497 | 3,532 | 3,498 | 3,526 | 3,543 | 3,574 | 3,607 | 3,641 | 3,668 | 3,697 | 3,724 |
| Peterborough - General Service Demand-Billed | 367 | 370 | 373 | 369 | 371 | 373 | 375 | 377 | 379 | 381 | 363 | 365 |
| Peterborough - Sub-transmission | | | | | | | | | | | 20 | 20 |
| Peterborough - Street Light | 13 | 13 | 13 | 16 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Peterborough - Sentinel Light | 110 | 109 | 108 | 107 | 106 | 104 | 103 | 102 | 101 | 100 | 99 | 98 |
| Peterborough - Unmetered Scattered Load | 10 | 10 | 10 | 10 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Sum ** | 1,397,014 | 1,411,655 | 1,431,161 | 1,451,114 | 1,461,380 | 1,471,687 | 1,480,206 | 1,490,079 | 1,500,938 | 1,511,705 | 1,577,885 | 1,588,896 |

* Seasonal rate class was discontinued in 2023 with customers moved to R1, R2, and UR based on density factor.

** Sum does not include Orillia and Peterborough before 2031.

**Table E.4 - Hydro One Distribution Load History and Forecast in GWh**

| Year | Actual/Forecast GWh | % Change | Normalized Weather (GWh) | % Change |
|---|---|---|---|---|
| 2021 | 39,200 | 2.8 | 36,131 | 0.9 |
| 2022 | 38,687 | -1.3 | 38,404 | 6.3 |
| 2023 | 38,807 | 0.3 | 39,749 | 3.5 |
| 2024 | 39,957 | 3.0 | 40,459 | 1.8 |
| 2025 | 41,573 | 4.0 | 40,997 | 1.3 |
| 2026 | 41,002 | -1.4 | 41,002 | 0.0 |
| 2027 | 41,027 | 0.1 | 41,027 | 0.1 |
| 2028 | 41,372 | 0.8 | 41,372 | 0.8 |
| 2029 | 42,031 | 1.6 | 42,031 | 1.6 |
| 2030 | 42,675 | 1.5 | 42,675 | 1.5 |
| 2031* | 43,875 | 2.8 | 43,875 | 2.8 |
| 2032* | 44,520 | 1.5 | 44,520 | 1.5 |

** Includes the impact of integrating Orillia and Peterborough into Hydro One Distribution.*

1 **Table E.5 - Actual Sales and Forecast in GWh**

| Rate Class | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Generator | 31 | 32 | 32 | 32 | 34 | 35 | 37 | 37 | 38 | 40 | 41 | 43 |
| General Service - Demand Billed | 2,556 | 2,337 | 2,230 | 2,319 | 2,615 | 2,555 | 2,568 | 2,250 | 2,293 | 2,336 | 2,378 | 2,420 |
| General Service - Energy Billed | 2,424 | 2,526 | 2,525 | 2,509 | 2,267 | 2,200 | 2,196 | 2,460 | 2,488 | 2,516 | 2,543 | 2,570 |
| Residential - Medium Density | 5,255 | 5,401 | 5,592 | 5,779 | 5,954 | 6,039 | 6,012 | 5,762 | 5,905 | 6,046 | 6,186 | 6,326 |
| Residential - Low Density | 4,990 | 5,147 | 5,612 | 5,936 | 6,069 | 5,818 | 5,738 | 5,683 | 5,773 | 5,861 | 5,949 | 6,036 |
| Seasonal * | 704 | 704 | | | | | | | | | | |
| Sub-transmission | 15,806 | 15,484 | 15,910 | 16,224 | 17,064 | 16,903 | 16,993 | 17,145 | 17,356 | 17,561 | 17,124 | 17,320 |
| Urban General Service - Demand Billed | 1,053 | 951 | 913 | 947 | 1,097 | 1,067 | 1,074 | 1,154 | 1,173 | 1,191 | 1,210 | 1,228 |
| Urban General Service - Energy Billed | 639 | 641 | 642 | 660 | 703 | 682 | 685 | 772 | 783 | 795 | 807 | 818 |
| Urban Residential | 2,074 | 2,079 | 2,074 | 2,213 | 2,326 | 2,323 | 2,356 | 2,719 | 2,782 | 2,844 | 2,907 | 2,968 |
| Street Light | 82 | 83 | 78 | 74 | 81 | 80 | 80 | 81 | 82 | 83 | 84 | 85 |
| Sentinel Light | 12 | 11 | 11 | 10 | 8 | 8 | 8 | 9 | 9 | 9 | 9 | 9 |
| Unmetered Scattered Load | 34 | 35 | 31 | 33 | 34 | 35 | 35 | 34 | 35 | 36 | 37 | 38 |
| Acquired Residential | 357 | 339 | 336 | 330 | 387 | 380 | 377 | 378 | 379 | 381 | 382 | 384 |
| Acquired General Service - Energy Billed | 141 | 120 | 115 | 114 | 123 | 118 | 117 | 117 | 117 | 117 | 117 | 117 |
| Acquired General Service - Demand Billed | 279 | 237 | 228 | 224 | 190 | 182 | 180 | 180 | 181 | 181 | 181 | 181 |
| Acquired Urban Residential | 125 | 119 | 118 | 119 | 121 | 120 | 121 | 123 | 125 | 127 | 129 | 131 |
| Acquired Urban General Service - Energy Billed | 49 | 43 | 40 | 41 | 44 | 43 | 44 | 45 | 46 | 47 | 48 | 50 |
| Acquired Urban General Service - Demand Billed | 218 | 185 | 117 | 116 | 107 | 104 | 104 | 105 | 106 | 107 | 109 | 110 |
| Orillia - Residential | 112 | 104 | 101 | 102 | 116 | 114 | 115 | 117 | 118 | 120 | 122 | 123 |
| Orillia - General Service Energy-Billed | 52 | 44 | 41 | 42 | 49 | 50 | 50 | 51 | 52 | 52 | 53 | 54 |
| Orillia - General Service Demand-Billed | 188 | 157 | 147 | 151 | 159 | 154 | 155 | 158 | 160 | 162 | 96 | 98 |
| Orillia - Sub-transmission | | | | | | | | | | | 68 | 68 |
| Orillia - Street Light | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.39 | 0.39 | 0.39 | 0.40 | 0.40 |
| Orillia - Unmetered Scattered Load | 0.84 | 0.84 | 0.84 | 0.84 | 0.85 | 0.65 | 0.65 | 0.65 | 0.66 | 0.67 | 0.67 | 0.68 |
| Peterborough - Residential | 316 | 294 | 287 | 298 | 306 | 303 | 305 | 309 | 314 | 320 | 326 | 332 |
| Peterborough - General Service Energy-Billed | 129 | 107 | 100 | 111 | 116 | 113 | 113 | 114 | 116 | 117 | 119 | 121 |
| Peterborough - General Service Demand-Billed | 419 | 349 | 327 | 352 | 383 | 373 | 375 | 378 | 380 | 382 | 222 | 223 |
| Peterborough - Sub-transmission | | | | | | | | | | | 163 | 164 |
| Peterborough - Street Light | 2.50 | 2.50 | 2.50 | 3.09 | 3.02 | 3.08 | 3.08 | 3.08 | 3.08 | 3.08 | 3.09 | 3.09 |
| Peterborough - Sentinel Light | 0.21 | 0.21 | 0.21 | 0.27 | 0.27 | 0.26 | 0.26 | 0.40 | 0.39 | 0.39 | 0.39 | 0.39 |
| Peterborough - Unmetered Scattered Load | 0.71 | 0.71 | 0.71 | 1.51 | 1.48 | 1.51 | 1.51 | 1.51 | 1.51 | 1.51 | 1.51 | 1.52 |
| Sum ** | 36,830 | 36,473 | 36,602 | 37,680 | 39,224 | 38,694 | 38,723 | 39,053 | 39,673 | 40,279 | 41,415 | 42,023 |

* Seasonal rate class was discontinued in 2023 with customers moved to R1, R2, and UR based on density factor.

** The sum does not include Orillia and Peterborough before 2031.

1 **Table E.6 - Weather Corrected Sales and Forecast in GWh**

| Rate Class | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Generator | 31 | 32 | 32 | 32 | 34 | 35 | 37 | 37 | 38 | 40 | 41 | 43 |
| General Service - Demand Billed | 2,213 | 2,307 | 2,308 | 2,355 | 2,552 | 2,555 | 2,568 | 2,250 | 2,293 | 2,336 | 2,378 | 2,420 |
| General Service - Energy Billed | 2,098 | 2,494 | 2,613 | 2,548 | 2,213 | 2,200 | 2,196 | 2,460 | 2,488 | 2,516 | 2,543 | 2,570 |
| Residential - Medium Density | 4,831 | 5,369 | 5,721 | 5,853 | 5,882 | 6,039 | 6,012 | 5,762 | 5,905 | 6,046 | 6,186 | 6,326 |
| Residential - Low Density | 4,587 | 5,116 | 5,742 | 6,012 | 5,995 | 5,818 | 5,738 | 5,683 | 5,773 | 5,861 | 5,949 | 6,036 |
| Seasonal * | 647 | 699 | | | | | | | | | | |
| Sub-transmission | 15,254 | 15,396 | 16,199 | 16,384 | 16,883 | 16,903 | 16,993 | 17,145 | 17,356 | 17,561 | 17,124 | 17,320 |
| Urban General Service - Demand Billed | 863 | 936 | 961 | 972 | 1,065 | 1,067 | 1,074 | 1,154 | 1,173 | 1,191 | 1,210 | 1,228 |
| Urban General Service - Energy Billed | 524 | 630 | 676 | 677 | 682 | 682 | 685 | 772 | 783 | 795 | 807 | 818 |
| Urban Residential | 1,921 | 2,067 | 2,120 | 2,240 | 2,299 | 2,323 | 2,356 | 2,719 | 2,782 | 2,844 | 2,907 | 2,968 |
| Street Light | 82 | 83 | 78 | 74 | 81 | 80 | 80 | 81 | 82 | 83 | 84 | 85 |
| Sentinel Light | 12 | 11 | 11 | 10 | 8 | 8 | 8 | 9 | 9 | 9 | 9 | 9 |
| Unmetered Scattered Load | 34 | 35 | 31 | 33 | 34 | 35 | 35 | 34 | 35 | 36 | 37 | 38 |
| Acquired Residential | 330 | 338 | 343 | 333 | 383 | 380 | 377 | 378 | 379 | 381 | 382 | 384 |
| Acquired General Service - Energy Billed | 115 | 118 | 122 | 117 | 120 | 118 | 117 | 117 | 117 | 117 | 117 | 117 |
| Acquired General Service - Demand Billed | 229 | 233 | 240 | 230 | 184 | 182 | 180 | 180 | 181 | 181 | 181 | 181 |
| Acquired Urban Residential | 116 | 118 | 121 | 120 | 120 | 120 | 121 | 123 | 125 | 127 | 129 | 131 |
| Acquired Urban General Service - Energy Billed | 40 | 42 | 42 | 42 | 42 | 43 | 44 | 45 | 46 | 47 | 48 | 50 |
| Acquired Urban General Service - Demand Billed | 178 | 182 | 123 | 119 | 104 | 104 | 104 | 105 | 106 | 107 | 109 | 110 |
| Orillia - Residential | 103 | 103 | 103 | 103 | 115 | 114 | 115 | 117 | 118 | 120 | 122 | 123 |
| Orillia - General Service Energy-Billed | 43 | 43 | 43 | 43 | 48 | 50 | 50 | 51 | 52 | 52 | 53 | 54 |
| Orillia - General Service Demand-Billed | 154 | 155 | 154 | 155 | 154 | 154 | 155 | 158 | 160 | 162 | 96 | 98 |
| Orillia - Sub-transmission | | | | | | | | | | | 68 | 68 |
| Orillia - Street Light | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.39 | 0.39 | 0.39 | 0.40 | 0.40 |
| Orillia - Unmetered Scattered Load | 0.84 | 0.84 | 0.84 | 0.84 | 0.85 | 0.65 | 0.65 | 0.65 | 0.66 | 0.67 | 0.67 | 0.68 |
| Peterborough - Residential | 292 | 292 | 293 | 301 | 302 | 303 | 305 | 309 | 314 | 320 | 326 | 332 |
| Peterborough - General Service Energy-Billed | 105 | 105 | 106 | 114 | 113 | 113 | 113 | 114 | 116 | 117 | 119 | 121 |
| Peterborough - General Service Demand-Billed | 343 | 343 | 344 | 362 | 372 | 373 | 375 | 378 | 380 | 382 | 222 | 223 |
| Peterborough - Sub-transmission | | | | | | | | | | | 163 | 164 |
| Peterborough - Street Light | 2.50 | 2.50 | 2.50 | 3.09 | 3.02 | 3.08 | 3.08 | 3.08 | 3.08 | 3.08 | 3.09 | 3.09 |
| Peterborough - Sentinel Light | 0.21 | 0.21 | 0.21 | 0.27 | 0.27 | 0.26 | 0.26 | 0.40 | 0.39 | 0.39 | 0.39 | 0.39 |
| Peterborough - Unmetered Scattered Load | 0.71 | 0.71 | 0.71 | 1.51 | 1.48 | 1.51 | 1.51 | 1.51 | 1.51 | 1.51 | 1.51 | 1.52 |
| Sum ** | 34,105 | 36,207 | 37,482 | 38,151 | 38,682 | 38,694 | 38,723 | 39,053 | 39,673 | 40,279 | 41,415 | 42,023 |

* Seasonal rate class was discontinued in 2023 with customers moved to R1, R2, and UR based on density factor.

** The sum does not include Orillia and Peterborough before 2031.

## Table E.7a - Actual and Forecast for Billing Peak in kW

| Year | Dgen | GSd | ST | UGd | Acquired GSd | Acquired UGd | Orillia GSd | Orillia ST | Peterbo-rough GSd | Peterbo-rough ST | Sum * |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | 227,745 | 7,626,142 | 25,424,747 | 2,423,030 | 489,983 | 306,842 | 329,517 | | 761,769 | | 36,498,488 |
| 2022 | 221,271 | 6,996,209 | 25,711,387 | 2,262,831 | 388,079 | 279,387 | 349,306 | | 807,555 | | 35,859,163 |
| 2023 | 240,588 | 7,694,782 | 32,060,717 | 2,517,732 | 391,656 | 282,925 | 347,880 | | 803,843 | | 43,188,400 |
| 2024 | 243,347 | 7,094,821 | 34,426,105 | 2,307,050 | 355,690 | 269,407 | 335,959 | | 814,989 | | 44,696,421 |
| 2025 | 254,890 | 7,437,080 | 34,776,764 | 2,473,163 | 385,702 | 280,952 | 351,932 | | 850,972 | | 45,608,552 |
| 2026 | 262,181 | 7,444,777 | 34,817,961 | 2,460,114 | 381,557 | 280,684 | 352,021 | | 852,933 | | 45,647,274 |
| 2027 | 270,534 | 7,483,083 | 35,003,345 | 2,457,469 | 377,077 | 280,186 | 353,279 | | 858,421 | | 45,871,693 |
| 2028 | 271,009 | 6,338,326 | 34,896,039 | 2,519,028 | 362,669 | 272,197 | 345,950 | | 830,216 | | 44,659,269 |
| 2029 | 282,446 | 6,460,914 | 35,325,843 | 2,543,047 | 363,091 | 275,221 | 350,080 | | 834,250 | | 45,250,562 |
| 2030 | 293,766 | 6,580,880 | 35,742,559 | 2,566,280 | 363,524 | 278,248 | 354,596 | | 839,866 | | 45,825,256 |
| 2031* | 305,033 | 6,699,663 | 34,853,539 | 2,589,500 | 364,007 | 281,307 | 207,510 | 151,556 | 528,792 | 407,171 | 46,388,078 |
| 2032* | 316,282 | 6,818,652 | 35,251,272 | 2,612,591 | 364,501 | 284,371 | 211,946 | 151,518 | 532,289 | 409,864 | 46,953,285 |

* The sum does not include Orillia and Peterborough before 2031.

## Table E.7b - Weather Corrected Actual and Forecast for Billing Peak in kW

| Year | Dgen | GSd | ST | UGd | Acquired GSd | Acquired UGd | Orillia GSd | Orillia ST | Peterbo-rough GSd | Peterbo-rough ST | Sum * |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | 227,745 | 7,752,490 | 26,050,891 | 2,459,715 | 497,401 | 311,487 | 334,506 | | 773,302 | | 37,299,729 |
| 2022 | 221,271 | 6,726,787 | 25,257,285 | 2,169,944 | 372,149 | 267,918 | 334,967 | | 774,406 | | 35,015,355 |
| 2023 | 240,588 | 7,453,889 | 31,764,299 | 2,431,958 | 378,313 | 273,287 | 336,029 | | 776,458 | | 42,542,334 |
| 2024 | 243,347 | 7,126,839 | 34,814,053 | 2,308,109 | 355,854 | 269,531 | 336,113 | | 815,363 | | 45,117,731 |
| 2025 | 254,890 | 7,190,522 | 34,363,386 | 2,375,977 | 370,546 | 269,911 | 338,103 | | 817,532 | | 44,825,232 |
| 2026 | 262,181 | 7,197,964 | 34,404,092 | 2,363,441 | 366,563 | 269,654 | 338,188 | | 819,416 | | 44,863,896 |
| 2027 | 270,534 | 7,235,000 | 34,587,273 | 2,360,900 | 362,259 | 269,176 | 339,396 | | 824,688 | | 45,085,141 |
| 2028 | 271,009 | 6,338,326 | 34,896,039 | 2,519,028 | 362,669 | 272,197 | 345,950 | | 830,216 | | 44,659,269 |
| 2029 | 282,446 | 6,460,914 | 35,325,843 | 2,543,047 | 363,091 | 275,221 | 350,080 | | 834,250 | | 45,250,562 |
| 2030 | 293,766 | 6,580,880 | 35,742,559 | 2,566,280 | 363,524 | 278,248 | 354,596 | | 839,866 | | 45,825,256 |
| 2031* | 305,033 | 6,699,663 | 34,853,539 | 2,589,500 | 364,007 | 281,307 | 207,510 | 151,556 | 528,792 | 407,171 | 46,388,078 |
| 2032* | 316,282 | 6,818,652 | 35,251,272 | 2,612,591 | 364,501 | 284,371 | 211,946 | 151,518 | 532,289 | 409,864 | 46,953,285 |

* The sum does not include Orillia and Peterborough before 2031.

## Table E.8 - Hydro One Distribution CDM Impacts (GWh) by Rate Class

| Rate Class | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Generator | | | | | | | | | | | | |
| General Service - Demand Billed | 481 | 509 | 609 | 663 | 705 | 740 | 773 | 804 | 833 | 860 | 878 | 890 |
| General Service - Energy Billed | 563 | 596 | 713 | 741 | 788 | 827 | 864 | 898 | 931 | 961 | 981 | 995 |
| Residential - Medium Density | 389 | 413 | 522 | 551 | 586 | 615 | 643 | 668 | 692 | 715 | 729 | 740 |
| Residential - Low Density | 340 | 362 | 533 | 563 | 599 | 629 | 657 | 683 | 708 | 731 | 746 | 756 |
| Seasonal * | 103 | 107 | | | | | | | | | | |
| Sub-transmission | 1,475 | 1,563 | 1,869 | 1,985 | 2,113 | 2,216 | 2,317 | 2,408 | 2,495 | 2,575 | 2,488 | 2,522 |
| Urban General Service - Demand Billed | 198 | 210 | 251 | 271 | 288 | 302 | 316 | 328 | 340 | 351 | 358 | 363 |
| Urban General Service - Energy Billed | 142 | 150 | 179 | 192 | 204 | 214 | 224 | 233 | 241 | 249 | 254 | 257 |
| Urban Residential | 141 | 150 | 179 | 198 | 210 | 221 | 231 | 240 | 248 | 256 | 262 | 266 |
| Street Light | | | | | | | | | | | | |
| Sentinel Light | | | | | | | | | | | | |
| Unmetered Scattered Load | | | | | | | | | | | | |
| Acquired Residential | 36 | 38 | 46 | 49 | 52 | 54 | 57 | 59 | 61 | 63 | 64 | 65 |
| Acquired General Service - Energy Billed | 13 | 13 | 16 | 17 | 18 | 19 | 20 | 21 | 21 | 22 | 22 | 23 |
| Acquired General Service - Demand Billed | 25 | 27 | 32 | 34 | 36 | 38 | 39 | 41 | 42 | 43 | 44 | 45 |
| Acquired Urban Residential | 21 | 22 | 27 | 28 | 30 | 32 | 33 | 34 | 35 | 37 | 37 | 38 |
| Acquired Urban General Service - Energy Billed | 16 | 17 | 20 | 22 | 23 | 25 | 26 | 27 | 28 | 28 | 29 | 29 |
| Acquired Urban General Service - Demand Billed | 46 | 49 | 59 | 62 | 66 | 69 | 72 | 75 | 78 | 80 | 81 | 82 |
| Orillia - Residential | 15 | 16 | 19 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 27 | 28 |
| Orillia - General Service Energy-Billed | 6 | 6 | 8 | 8 | 9 | 9 | 10 | 10 | 10 | 11 | 11 | 11 |
| Orillia - General Service Demand-Billed | 21 | 22 | 27 | 28 | 30 | 31 | 33 | 34 | 35 | 36 | 22 | 22 |
| Orillia - Sub-transmission | | | | | | | | | | | 15 | 15 |
| Orillia - Street Light | | | | | | | | | | | | |
| Orillia - Unmetered Scattered Load | | | | | | | | | | | | |
| Peterborough - Residential | 35 | 37 | 44 | 47 | 50 | 53 | 55 | 57 | 59 | 61 | 62 | 63 |
| Peterborough - General Service Energy-Billed | 19 | 20 | 23 | 25 | 26 | 28 | 29 | 30 | 31 | 32 | 33 | 33 |
| Peterborough - General Service Demand-Billed | 43 | 46 | 55 | 58 | 62 | 65 | 68 | 70 | 73 | 75 | 31 | 32 |
| Peterborough - Sub-transmission | | | | | | | | | | | 45 | 46 |
| Peterborough - Street Light | | | | | | | | | | | | |
| Peterborough - Sentinel Light | | | | | | | | | | | | |
| Peterborough - Unmetered Scattered Load | | | | | | | | | | | | |
| Sum ** | 3,990 | 4,226 | 5,055 | 5,374 | 5,719 | 5,998 | 6,270 | 6,518 | 6,753 | 6,970 | 7,220 | 7,320 |

* Seasonal rate class was discontinued in 2023 with customers moved to R1, R2, and UR based on density factor.

** The sum does not include Orillia and Peterborough before 2031.

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# DATA FOR HYDRO ONE DISTRIBUTION LOAD FORECAST

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# APPENDIX 2-IB: CUSTOMER, CONNECTIONS, LOAD FORECAST AND REVENUES DATA AND ANALYSIS

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# DERIVATION OF DEMAND USING LOAD FACTOR

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