SUMMARY OF REVENUE REQUIREMENT

1.0 INTRODUCTION

The revenue requirements presented below for Transmission, Section 2, and for Distribution, Section 3, 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 requested in the current application incorporate Hydro One's upfront commitment to deliver efficiencies and improved productivity to customers.

The Transmission revenue requirement requested 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 necessary investments to address system needs and service obligations, and invest in infrastructure that is essential to core business functions and operations.

The Distribution revenue requirement requested represents the funding necessary to serve the 1.4M 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 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 begins by summarizing the revenue requirement requested by Hydro One for Transmission for the 2023 rebasing year. The remaining Transmission sections address individual components of the calculation of the Transmission revenue requirement in the 2023 rebasing year. Attachments 1-5 to this Exhibit provide the full details of the Transmission revenue requirement for each year in the rate period (2023 to 2027).

Section 3 begins by summarizing the revenue requirement requested by Hydro One for Distribution. The remaining Distribution sections address individual components of the calculation of the Distribution revenue requirement in the 2023 rebasing year. Attachments 6-10 to this Exhibit provide the full details of the Distribution revenue requirement for each year in the rate period (2023 to 2027).

Section 4 describes the Environmental Provision add-back to OM&A and the offsetting Environmental Provision reduction to Depreciation and Amortization expense with respect of the PCB Retirement and Waste Management program (the PCB Program).

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 with the exception of the proposed treatment of the PCB Program discussed below in Section 4.0. The results of these calculations are summarized in Table 1.

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

Components	**2020 Rebasing Year** Note 1	**2021** Note 2	**2022** Note 3	**2023 Rebasing Year**	**Reference**
OM&A	385.0	-	-	420.5	Exhibit E-02-01
Environmental Provision addback to OM&A	-	-	-	7.6	Section 2.1.1
Depreciation and Amortization	473.4	-	-	535.8	Exhibit E-08-01
Environmental Provision reduction to Amortization Expense	-	-	-	-7.6	Section 2.1.2
Income Taxes	30.1	-	-	40.5	Exhibit E-09-02
Return on Capital	741.0	-	-	826.3	Exhibit F-01-01
Total Revenue Requirement	**1,629.6**	**1,704.3**	**1,807.6**	**1,823.2**	

Note 1: Represents OEB approved 2020 revenue requirement in EB-2019-0082
Note 2: Represents OEB approved 2021 revenue requirement in 2021 Annual Update in EB-2020-0202
Note 3: 2022 Revenue Requirement = $1,704.3(2021 Revenue Requirement)(1 + (2.00% inflation factor - 0.30% stretch factor + 2.70% capital factor)) + $28.4(DTA Recovery) = $1,807.6. 2022 OEB approved revenue requirement to be established as part of the 2022 Annual Update.*

2.1 CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

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

[1] Rounded figures within tables may not add up resulting from rounding

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)

	2023	Reference
Sustainment	219.6	Exhibit E-02-02
Development	8.6	Exhibit E-02-03
Operations	49.0	Exhibit E-04-05
Customer Care	6.9	Exhibit E-02-04
Common and Other	65.0	Exhibit E-04-01
Property Taxes and Rights Payments	71.4	Exhibit E-09-04
Subtotal OM&A	**420.5**	Exhibit E-02-01
Environmental Provision add-back to OM&A	7.6	Exhibit E-08-01
Total OM&A for Revenue Requirement	**428.1**	

For more details on the associated costs surrounding OM&A, please refer to the exhibit references noted in Table 2 above. The environmental provision add-back to OM&A costs in Table 2 above and an offsetting Environmental Provision reduction to Depreciation and Amortization expense in Table 3 below, as proposed by Hydro One in the 2023 rebasing year relates to the PCB Program and is further described in detail in Section 4.0.

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)

	2023	Reference
Depreciation	528.2	
Amortization	7.6	
Subtotal Expense	**535.8**	Exhibit E-08-01
Environmental Provision reduction to Amortization Expense	(7.6)	Exhibit E-08-01
Total Expense for Revenue Requirement	**528.2**	

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)

	2023	Reference
Regulatory Taxable Income	154.1	
Tax Rate	26.5%	
Subtotal	**40.8**	
Less: Tax Credits	(0.3)	
Total Income Taxes	**40.5**	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)

	2023	Reference
Debt Cost	339.5	
Return on Equity	486.8	
Return on Capital	**826.3**	Exhibit F-01-03

2.2 TRANSMISSION REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

2.2.1 2023 COMPARED TO 2022

The forecast OEB approved Transmission revenue requirement for 2022 ($1,807.6M) is shown in Table 1 above. This forecast was derived by escalating the 2020 base year revenue requirement by the Custom IR Formula into 2021 and 2022.[2] The requested 2023 Transmission Revenue Requirement represents an increase of 0.9% as compared to the 2022 forecast, or about $15.6M. This increase is below the expected rate of inflation, and is predominantly driven by investments in the work program necessary to achieve outcomes that are valued by customers and required to sustain safe and reliable transmission system operations, to maintain equipment performance and to fund necessary investments to address system needs and service obligations, partly offset by benefits arising from rebasing in 2023, such as a reduced cost of capital and incremental productivity gains as further described in SPF Section 1.4.

[2] The inflation rate assumed for 2022 in the Custom IR Formula is 2.00%, which is equal to the OEB approved 2021 inflation factor for electricity transmitters. Additionally, 2022 revenue requirement includes DTA recovery of $28.4M.

2.2.2 2023 COMPARED TO 2020

Table 6 below shows the dollar amounts and percentage changes obtained by comparing the value of key elements in the 2023 proposed Revenue Requirement with the corresponding values in the 2020 OEB-approved Revenue Requirement (as per EB-2019-0082). 2020 is used as the basis for this line-by-line comparison as it represents the latest approved rebasing year for Hydro One Transmission where actual figures are available.

This increase is predominantly driven by rate base growth, higher income taxes as a result of the reversal of deferred tax asset sharing (EB-2020-0194), and higher OM&A (further described in Exhibit E-02-01). This is partially offset by lower cost of debt.

Table 6 - Impact of Individual Components on Transmission Revenue Requirement

Description	2023 vs. 2020	2023 vs. 2020
	($M)	(%)
Increase in OM&A	35.5	2%
Environmental Provision addback to OM&A	7.6	1%
Rate Base Growth	181.2	11%
Lower ROE	-8.9	-1%
Lower cost of debt	-32.3	-2%
Tax	10.4	1%
Impact on Revenue Requirement	**193.6**	**12%**

3.0 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 with the exception of the proposed treatment of the PCB Program discussed below in Section 4.0. The results of these calculations are summarized in Table 7.

Table 7 - Distribution Revenue Requirement ($M)[3]

Components	2018 Rebasing Year *Note 1*	2019 *Note 1*	2020 *Note 2*	2021 *Note 3*	2022 *Note 4*	2023 Rebase Year	Reference
OM&A	544.4	-	-	-	-	597.5	Exhibit E-03-01
Environmental Provision add-back to OM&A	-	-	-	-	-	5.5	Section 3.1.1
Depreciation and Amortization	397.8	-	-	-	-	465.6	Exhibit E-08-01
Environmental Provision reduction to Amortization Expense	-	-	-	-	-	-5.5	Section 3.1.2
Income Taxes	43.1	-	-	-	-	37.2	Exhibit E-09-02
Return on Capital	473.2	-	-	-	-	532.1	Exhibit F-01-01
Total Revenue Requirement	**1,458.5**	**1,497.9**	**1,539.2**	**1,596.2**	**1,674.6**	**1,632.4**	

Note 1: Represents OEB approved 2018 and 2019 revenue requirement in EB-2017-0049
Note 2: Represents OEB approved 2020 revenue requirement in 2020 Annual Update in EB-2019-0043
Note 3: Represents OEB approved 2021 revenue requirement in 2021 Annual Update in EB-2020-0030
Note 4: 2022 Revenue Requirement = $1,596.2(2021 Revenue Requirement)(1 + (2.20% inflation factor - 0.45% stretch factor + 1.85% capital factor)) + $21.0(DTA Recovery) = $1,674.6. 2022 OEB approved revenue requirement to be established as part of the 2022 Annual Update.*

The above 2023 Revenue Requirement forecast noted in Table 7 includes the revenue requirement associated with the integration of the Acquired Utilities, which contributes $30.0M to the revenue requirement in 2023 relative to 2022 approved levels.[4]

3.1 CALCULATION OF DISTRIBUTION REVENUE REQUIREMENT

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

[3] Rounded figures within tables may not add up resulting from rounding
[4] The additional revenue requirement due to the integration of the Acquired Utilities is broken down as follows: $9.8M for Norfolk, $13.1M for Haldimand and $7.0M for Woodstock.

3.1.1 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)

	2023	Reference
Sustainment	311.4	Exhibit E-03-02
Development	11.0	Exhibit E-03-03
Operations	40.8	Exhibit E-04-05
Customer Care	118.3	Exhibit E-03-04
Common and Other	110.0	Exhibit E-04-01
Property Taxes and Rights Payments	6.0	Exhibit E-09-04
Subtotal OM&A	**597.5**	Exhibit E-03-01
Environmental Provision add-back to OM&A	5.5	Exhibit E-08-01
Total OM&A for Revenue Requirement	**603.0**	

For more details on the associated costs surrounding OM&A, please refer to the exhibit references noted in Table 8 above. As explained in detail below in Section 4.0, certain adjustments related to the completion of PCB Program in 2023 have been made in calculating the Distribution Revenue Requirement.

3.1.2 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)

	2023	Reference
Depreciation	460.1	
Amortization	5.5	
Subtotal Expense	**465.6**	Exhibit E-08-01
Environmental Provision reduction to Amortization Expense	(5.5)	Exhibit E-08-01
Total Expense for Revenue Requirement	**460.1**	

3.1.3 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)

	2023	Reference
Regulatory Taxable Income	141.9	
Tax Rate	26.5%	
Subtotal	**37.6**	
Less: Tax Credits	(0.4)	
Total Income Taxes	**37.2**	Exhibit E-09-02 Attachment 1

3.1.4 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.

Table 11 - Distribution Return on Capital ($M)

	2023	Reference
Debt Cost	219.4	
Return on Equity	312.7	
Return on Capital	**532.1**	Exhibit F-01-03

3.2 DISTRIBUTION REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

3.2.1 2023 COMPARED TO 2022

The forecast OEB approved Distribution revenue requirement for 2022 ($1,674.6M) is shown in Table 7 above. This forecast was derived by escalating the 2018 base year revenue requirement by the Custom IR Formula into 2019, 2020, 2021 and 2022.[5] The requested 2023 Distribution Revenue Requirement represents a decrease of about 2.5% compared to the 2022 forecast or about $42.2M. This decrease is predominantly driven by benefits arising from rebasing in 2023, such as a reduced cost of debt and incremental productivity gains as further described in SPF Section 1.4, partly offset by investments necessary provide safe and reliable distribution of power and sufficient grid capacity to accommodate customer demand and align with customer preferences, increases to OM&A due to the inclusion of OPEB non-service costs and the incremental revenue requirement related to the Acquired Utilities in 2023.

As previously described, 2023 includes an incremental $30.0M of revenue requirement related to Acquired Utilities, which is not included in the 2022 OEB approved forecast. If 2023 is adjusted to exclude this amount, which provides for a more comparable analysis, then the decrease in revenue requirement relative to the forecasted 2022 OEB approved amount results in a reduction of about 4.3% or about $72.2M.

3.2.2 2023 COMPARED TO 2018

Table 12 below shows the dollar amounts and percentage changes obtained by comparing the value of key elements in the Year 2023 proposed Distribution Revenue Requirement with the corresponding values in the Year 2018 approved Revenue Requirement (as per EB-2017-0049). 2018 is used as the basis of comparison, instead of 2022, as it represents the latest approved rebasing year for Hydro One Distribution where actual figures are available.

The increase in revenue requirement is predominantly driven by rate base growth, higher OM&A due to the inclusion of OPEB non-service costs and the revenue requirement related to the inclusion of Acquired Utilities. This is partially offset by lower cost of debt, lower return on equity, and lower income taxes resulting from increased tax deductions largely relating to

[5] The inflation rate assumed for 2022 in the Custom IR Formula is 2.2%, which is equal to the OEB approved 2021 inflation factor for electricity distributors. Additionally, 2022 revenue requirement includes DTA recovery of $21.0M.

accelerated depreciation not previously planned in the prior application that has offset the reversal of deferred tax asset sharing (EB-2020-0194).

As noted above, the impact of the incremental revenue requirement associated with integrating the Acquired Utilities in 2023 is about 2%.

Table 12 - Impact of the Individual Component on Distribution Revenue Requirement

Description	**2023 vs. 2018**	**2023 vs. 2018**
	($M)	**(%)**
Increase in OM&A	40.9	3%
Environmental Provision addback to OM&A	5.5	0%
Rate Base Growth	143.6	10%
Lower ROE	-20.2	-1%
Lower Cost of Debt	-19.5	-1%
Tax	-6.5	0%
Acquired Utilities	30.0	2%
Impact on Revenue Requirement	**173.9**	**12%**

4.0 ENVIRONMENTAL PROVISION

The environmental provision add-back to OM&A costs (in Table 2 and Table 8) and an offsetting Environmental Provision reduction to Depreciation and Amortization expense (in Table 3 and Table 9), as proposed by Hydro One in the 2023 rebasing year for both Transmission and Distribution, relates to the PCB Program. The PCB Program forms part of Hydro One's broader Environmental Management program and involves managing, testing and disposing of PCB waste as part of Hydro One's normal business operations. Federal environmental legislation requires the PCB Program to be completed by year-end of 2025.

The PCB Program is part of the Sustainment OM&A work undertaken by Hydro One for Transmission and Distribution as described in Exhibit E-02-02 and Exhibit E-03-02. These costs are included in Total Sustainment OM&A expenditures for Transmission and Distribution, as shown at Exhibits E-02-02 and E-03-02 and in Total OM&A costs, as shown at Exhibits E-02-01 and E-03-01.

As the PCB Program costs offset an environmental liability, which Hydro One established on its balance sheet, the required accounting treatment causes PCB Program expenses to be included as an amortization expense. This expense is shown on the Depreciation and Amortization line item for purposes of calculating revenue requirement rather than on the OM&A line. The proposed treatment of the PCB Program in the revenue requirement calculation for both Transmission and Distribution is to reclassify the program costs as an OM&A expense starting in 2023 with an equivalent offset to amortization expenses (Proposed Treatment). As further explained below, the Proposed Treatment is necessary to avoid an unwarranted reduction to OM&A expense after 2025.

In previous applications, the costs applicable to the PCB Program shown in Sustainment OM&A were offset by a corresponding negative amount under Common and Other OM&A and then recorded as an amortization expense under Depreciation and Amortization (Current Treatment). Treatment of these costs as an amortization expense is described in further detail in Exhibit E-08-01.

In this application for both Transmission and Distribution, the PCB Program will end in 2025 and will be replaced by other Sustainment OM&A work required to be undertaken over the remainder of the forecast period.

Hydro One Transmission plans to resume preventive maintenance on transmission stations and lines assets that were deferred in 2019-2022. These deferrals allowed, and will continue to allow, Hydro One to fund the planned PCB remediation work in 2021 and 2022. This work can no longer be deferred, as Hydro One’s asset management approach relies on sustaining asset performance to maintain transmission system safety and reliability. Thus, Hydro One must resume the proposed level of preventive maintenance and return this work to pre-2019 levels to ensure that necessary maintenance activities are completed in a timely manner, and that new capital replacement candidates are identified before equipment malfunctions or fails. This will, in turn, reduce the risk of unplanned equipment failure impacting the reliability of the transmission system. For more information on transmission preventive maintenance programs and the PCB program, refer to Exhibit E-02-02.

With respect to Hydro One Distribution, corrective maintenance work across the distribution system still continues after the work to remove PCB equipment has been completed. Deferral of some of this work will allow for the completion of the PCB work requirements by 2025. Hydro One has deferred corrective maintenance activities such as distribution lines defect corrections. Lines defects currently on Hydro One's system include broken grounding wires that can impact public safety and protection devices, as well as guying defects which provide support for lines during storms. Without these defects being corrected, Hydro One's protective equipment may not operate as designed and its lines could be more susceptible to failures during weather events. Over the past few years, Hydro One on average has addressed approximately 12,000 defects per year as part of the defect correction program, while the defect backlog has grown by an average of approximately 11,500 defects per year. As PCB remediation is reduced approaching the December 31st, 2025 deadline, funding will be required to help deal with the backlog of defects on the Hydro One distribution system. For more information on distribution Sustainment OM&A and the PCB program, refer to Exhibit E-03-02.

Under previous filing approaches and leveraging the current accounting treatment, there would have been no amortization expense recorded for PCB after 2025. The implication of this accounting treatment and the net result to total OM&A for purposes of calculating revenue requirement would be that the level of OM&A work funded in rates would have declined by the amount of the PCB Program costs. As a result, there would be a projected shortfall in the revenue requirement by continuing to treat PCB costs as an amortization expense under the Current Treatment.

To enable continued Sustainment OM&A funding in revenue requirement that corresponds to the Sustainment OM&A work required over the test period, Hydro One developed the following Proposed Treatment. As shown in Table 2 and Table 8 above, the Proposed Treatment includes an environmental add-back provision in 2023, which is equal to the 2023 forecast PCB Program costs to be recovered in OM&A. Table 3 and Table 9 above shows the reduction to the depreciation and amortization expense, which offsets the accounting treatment of these costs and transfers them back to total OM&A costs for revenue requirement calculation purposes only.

While the Proposed Treatment will reclassify PCB costs, it will not change the overall amount recovered. PCB costs are an OM&A related expenditure that was previously accounted for in the capital related revenue requirement through its recognition as a depreciation and amortization expense, but will now be reclassified back to OM&A. As a result, under this approach, there will be no change to the total 2023 revenue requirement as the changes are strictly a reclassification.

The Proposed Treatment will allow the PCB Program to be treated in the same way as any other OM&A program. This treatment serves to fund expansions of existing work programs and new work programs that develop mid-term which are required to maintain the existing asset base. This proposed approach will also enable the review of forecast levels of Sustainment OM&A expenditure, inclusive of the PCB Program costs as part of approving Total OM&A for 2023. Furthermore, it provides the benefit of assessing all Sustaining OM&A work relative to the cost incurred to carry out that work.

This page left blank intentionally.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input [1]

		Initial Application		Adjustments	Application Update		Adjustments	Per Board Decision	
		($ millions)			($ millions)			($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$22,913			$ 22,913			$22,913	
	Accumulated Depreciation (average)	($8,352)	(5)		($8,352)			($8,352)	
	Allowance for Working Capital:								
	Controllable Expenses	$428			$ 428			$428	
	Cost of Power								
	Working Capital Rate (%)	7.5%	(9)			(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Transmission Revenue at Current Rates								
	Transmission Revenue at Proposed Rates	$1,763							
	Other Revenue:								
	Specific Service Charges								
	Non-rate revenues	$40							
	Export Revenue Credits	$37							
	LVSG + Regulatory Balances	($18)							
	Total Revenue Offsets	$60	(7)						
	Operating Expenses:								
	OM+A Expenses	$428			$ 428			$428	
	Depreciation/Amortization	$528			$ 528			$528	
	Property taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($373.2)	(3)						
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$29.8							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	($0.3)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
		100.0%							
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.04%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement. DVAs have been included within total offsets, as regulatory balances have been approved to be recovered through UTRs

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$22,912.6	$ -	$22,913	$ -	$22,913
2	Accumulated Depreciation (average)	(2)	($8,351.9)	$ -	($8,352)	$ -	($8,352)
3	Net Fixed Assets (average)	(2)	$14,560.7	$ -	$14,561	$ -	$14,561
4	Allowance for Working Capital	(1)	$32.0	($32)	$ -	$ -	$ -
5	**Total Rate Base**		$14,592.7	($32)	$14,561	$ -	$14,561

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$428.1	$ -	$428	$ -	$428
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$428.1	$ -	$428	$ -	$428
9	Working Capital Rate %	(1)	7.47%	-7.47%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$32.0	($32)	$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars	Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:					
1	Transmission Revenue (at Proposed Rates)	$1,763.3	($1,763)	$ -	$ -	$ -
2	Other Revenue [(1)]	$59.9	($60)	$ -	$ -	$ -
3	Total Operating Revenues	$1,823.2	($1,823)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$428	$ -	$428	$ -	$428
5	Depreciation/Amortization	$528	$ -	$528	$ -	$528
6	Property taxes	$ -	$ -		$ -	
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$956	$ -	$956	$ -	$956
10	Deemed Interest Expense	$340	($340)	$0	($0)	$ -
11	Total Expenses (lines 9 to 10)	$1,296	($340)	$956	($0)	$956
12	**Utility income before income taxes**	$527	($1,484)	($956)	$0	($956)
13	Income taxes (grossed-up)	$40	$ -	$40	$ -	$40
14	**Utility net income**	$487	($1,484)	($997)	$0	($997)

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
Specific Service Charges	$ -		$ -		$ -
Late Payment Charges	$40		$ -		$ -
Other Distribution Revenue	$37		$ -		$ -
Other Income and Deductions	($18)		$ -		$ -
Total Revenue Offsets	$59.9	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$527.3	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($373.2)	$ -	$ -
3	Taxable income	$154.1	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$29.8	$30	$30
6	Total taxes	$29.8	$30	$30
7	Gross-up of Income Taxes	$10.7	$11	$11
8	Grossed-up Income Taxes	$40.5	$40	$40
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$40.5	$40	$40
10	Other tax Credits	($0.3)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
					($ millions)
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$8,172	4.04%	$330.4
2	Short-term Debt	4.00%	$584	1.56%	$9.1
3	**Total Debt**	60.00%	$8,756	3.88%	$339.5
	Equity				
4	Common Equity	40.00%	$5,837	8.34%	$486.8
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$5,837	8.34%	$486.8
7	**Total**	100.00%	$14,593	5.66%	$826.3
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$0
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$0
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$14,561	0.00%	$0
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.04%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$14,561	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$1,301		$1,301
2	Transmission Revenue	$ -	$1,763	$ -	$463	$ -	($1,301)
3	Other Operating Revenue Offsets - net	$60	$60	$ -	$ -	$ -	$ -
4	**Total Revenue**	$60	$1,823.2	$ -	$1,763.3	$ -	$ -
5	Operating Expenses	$956	$956	$956	$956	$956	$956
6	Deemed Interest Expense	$340	$340	$0	$0	$ -	$ -
8	**Total Cost and Expenses**	$1,296	$1,296	$956	$956	$956	$956
9	**Utility Income Before Income Taxes**	($1,236)	$527.3	($956)	$807	($956)	($956.4)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($373)	($373)	($373)	($373)	$ -	$ -
11	**Taxable Income**	($1,609)	$154.1	($1,330)	$434	($956)	($956)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$40.8	$ -	$114.9	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	($1,236)	$486.8	($956)	($996.9)	($956)	($997)
16	**Utility Rate Base**	$14,593	$14,593	$14,561	$14,561	$14,561	$14,561
17	Deemed Equity Portion of Rate Base	$5,837	$5,837	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	-21.17%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-29.51%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	-6.14%	5.66%	-6.57%	0.00%	-6.57%	0.00%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-11.80%	0.00%	-6.57%	0.00%	-6.57%	0.00%
24	Target Return on Equity	$487	$487	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)		($0)	$956	$ -	$956	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$1,301 (1)		$1,301 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

For Transmission, revenue deficiency and sufficiency have been removed, as it does not yield the same level of comparability with Distribution

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$428.1		$428		$428	
2	Amortization/Depreciation	$528.2		$528		$528	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$40.5		$40		$40	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$339.5		$0		$ -	
	Return on Deemed Equity	$486.8		($0)		$ -	
8	**Service Revenue Requirement (before Revenues)**	$1,823.2		$997		$997	
9	Revenue Offsets	$59.9		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,763.3		$997		$997	
11	Transmission revenue	$1,763.3		$ -		$ -	
12	Other revenue	$59.9		$ -		$ -	
13	**Total revenue**	$1,823.2		$ -		$ -	
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	($0.0)	(1)	($997)	(1)	($997)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,823	$997	($0)	$997	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$1,301		$1,301	
Base Revenue Requirement (to be recovered from Rates)	$1,763	$997	($0)	$997	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,763	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,823.20**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** *(11)*

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year	Price Cap IR Period 1	Price Cap IR Period 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)
Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.
(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)
(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 826	5.66%	$ 14,593	$ 428	$ 32	$ 528	$ 40	$ 428	$ 1,823	$ 60	$ 1,763	$ -
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Data Input [1]

		Initial Application		Adjustments	Application Update		Adjustments	Per Board Decision	
		($ millions)	(2)		($ millions)	(6)		($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$24,197			$ 24,197			$24,197	
	Accumulated Depreciation (average)	($8,780)	(5)		($8,780)			($8,780)	
	Allowance for Working Capital:								
	Controllable Expenses	$437			$ 437			$437	
	Cost of Power								
	Working Capital Rate (%)	7.75%	(9)			(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Transmission Revenue at Current Rates								
	Transmission Revenue at Proposed Rates	$1,883							
	Other Revenue:								
	Specific Service Charges								
	Non-rate revenues	$36							
	Export Revenue Credits	$37							
	LVSG + Regulatory Balances	($19)							
	Total Revenue Offsets	$55	(7)						
	Operating Expenses:								
	OM+A Expenses	$437			$ 437			$437	
	Depreciation/Amortization	$558			$ 558			$558	
	Property taxes								
	Productivity adjustments	($2)			-2.327721855			($2)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($317)	(3)						
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$52.12							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	($0.3)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)		(8)			(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
		100.0%							
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.04%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement. DVAs have been included within total offsets, as regulatory balances have been approved to be recovered through UTRs

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$24,196.7	$ -	$24,197	$ -	$24,197
2	Accumulated Depreciation (average)	(2)	($8,780.2)	$ -	($8,780)	$ -	($8,780)
3	Net Fixed Assets (average)	(2)	$15,416.5	$ -	$15,416	$ -	$15,416
4	Allowance for Working Capital	(1)	$33.8	($34)	$ -	$ -	$ -
5	**Total Rate Base**		$15,450.3	($34)	$15,416	$ -	$15,416

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$436.7	$ -	$437	$ -	$437
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$436.7	$ -	$437	$ -	$437
9	Working Capital Rate %	(1)	7.75%	-7.75%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$33.8	($34)	$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Utility Income

Line No.	Particulars		Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$1,883.1	($1,883)	$ -	$ -	$ -
2	Other Revenue	(1)	$54.7	($55)	$ -	$ -	$ -
3	Total Operating Revenues		$1,937.8	($1,938)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$437	$ -	$437	$ -	$437
5	Depreciation/Amortization		$558	$ -	$558	$ -	$558
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($2)	$ -	($2)	$ -	($2)
9	Subtotal (lines 4 to 8)		$992	$ -	$992	$ -	$992
10	Deemed Interest Expense		$359	($359)	$0	($0)	$ -
11	Total Expenses (lines 9 to 10)		$1,351	($359)	$992	($0)	$992
12	**Utility income before income taxes**		$586	($1,578)	($992)	$0	($992)
13	Income taxes (grossed-up)		$71	$ -	$71	$ -	$71
14	**Utility net income**		$515	($1,578)	($1,063)	$0	($1,063)

Notes

Other Revenues / Revenue Offsets

Note	Item	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$36		$ -		$ -
	Other Distribution Revenue	$37		$ -		$ -
	Other Income and Deductions	($19)		$ -		$ -
	Total Revenue Offsets	$54.7	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$586.3	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($317.5)	$ -	$ -
3	Taxable income	$268.9	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$52.1	$52	$52
6	Total taxes	$52.1	$52	$52
7	Gross-up of Income Taxes	$18.8	$19	$19
8	Grossed-up Income Taxes	$70.9	$71	$71
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$70.9	$71	$71
10	Other tax Credits	($0.3)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$8,652	4.04%	$349.8
2	Short-term Debt	4.00%	$618	1.56%	$9.6
3	**Total Debt**	60.00%	$9,270	3.88%	$359.5
	Equity				
4	Common Equity	40.00%	$6,180	8.34%	$515.4
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,180	8.34%	$515.4
7	**Total**	100.00%	$15,450	5.66%	$874.9
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$0
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$0
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$15,416	0.00%	$0
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.04%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$15,416	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$1,349		$1,350
2	Transmission Revenue	$ -	$1,883	$ -	$534	$ -	($1,350)
3	Other Operating Revenue Offsets - net	$55	$55	$ -	$ -	$ -	$ -
4	**Total Revenue**	$55	$1,937.8	$ -	$1,883.1	$ -	$ -
5	Operating Expenses	$992	$992	$992	$992	$992	$992
6	Deemed Interest Expense	$359	$359	$0	$0	$ -	$ -
8	**Total Cost and Expenses**	$1,351	$1,351	$992	$992	$992	$992
9	**Utility Income Before Income Taxes**	($1,297)	$586.3	($992)	$891	($992)	($992.0)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($317)	($317)	($317)	($317)	$ -	$ -
11	**Taxable Income**	($1,614)	$268.9	($1,310)	$574	($992)	($992)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$71.2	$ -	$152.0	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	($1,296)	$515.4	($992)	($1,062.9)	($992)	($1,063)
16	**Utility Rate Base**	$15,450	$15,450	$15,416	$15,416	$15,416	$15,416
17	Deemed Equity Portion of Rate Base	$6,180	$6,180	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	-20.98%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-29.32%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	-6.06%	5.66%	-6.43%	0.00%	-6.43%	0.00%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-11.73%	0.00%	-6.43%	0.00%	-6.43%	0.00%
24	Target Return on Equity	$515	$515	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)		$0	$992	$ -	$992	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$1,349 (1)		$1,350 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Requirement

Line No.	Particulars	Application	Application Update	Per Board Decision
1	OM&A Expenses	$436.7	$437	$437
2	Amortization/Depreciation	$557.6	$558	$558
3	Property Taxes	$ -		
5	Income Taxes (Grossed up)	$70.9	$71	$71
6	Other Expenses	($2.3)	($2)	($2)
7	Return			
	Deemed Interest Expense	$359.5	$0	$ -
	Return on Deemed Equity	$515.4	($0)	$ -
8	**Service Revenue Requirement (before Revenues)**	$1,937.8	$1,063	$1,063
9	Revenue Offsets	$54.7	$ -	$ -
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,883.1	$1,063	$1,063
11	Transmission revenue	$1,883.1	$ -	$ -
12	Other revenue	$54.7	$ -	$ -
13	**Total revenue**	$1,937.8	$ -	$ -
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	$0.0 (1)	($1,063) (1)	($1,063) (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,938	$1,063	($0)	$1,063	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$1,349		$1,350	
Base Revenue Requirement (to be recovered from Rates)	$1,883	$1,063	($0)	$1,063	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,883	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,937.82**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year	Price Cap IR Period: 1	Price Cap IR Period: 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
	Customer Class From sheet 10. Load Forecast					From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
		Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance	$ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)
Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.
(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)
(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 875	5.66%	$ 15,450	$ 437	$ 34	$ 558	$ 71	$ 437	$ 1,938	$ 55	$ 1,883	$ -
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Data Input [(1)]

		Initial Application		Adjustments	Application Update		Adjustments	Per Board Decision	
		($ millions)			($ millions)			($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$25,650			$ 25,650			$25,650	
	Accumulated Depreciation (average)	($9,235)	(5)		($9,235)			($9,235)	
	Allowance for Working Capital:								
	Controllable Expenses	$445			$ 445			$445	
	Cost of Power								
	Working Capital Rate (%)	7.57%	(9)			(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Transmission Revenue at Current Rates								
	Transmission Revenue at Proposed Rates	$1,973							
	Other Revenue:								
	Specific Service Charges								
	Non-rate revenues	$36							
	Export Revenue Credits	$37							
	LVSG + Regulatory Balances	($19)							
	Total Revenue Offsets	$54	(7)						
	Operating Expenses:								
	OM+A Expenses	$445			$ 445			$445	
	Depreciation/Amortization	$594			$ 594			$594	
	Property taxes								
	Productivity adjustments	($5)			-4.649161366			($5)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($377)	(3)						
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$45.15							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	($0.3)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)		(8)			(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
		100.0%							
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.04%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$25,649.9	$ -	$25,650	$ -	$25,650
2	Accumulated Depreciation (average)	(2)	($9,234.8)	$ -	($9,235)	$ -	($9,235)
3	Net Fixed Assets (average)	(2)	$16,415.1	$ -	$16,415	$ -	$16,415
4	Allowance for Working Capital	(1)	$33.7	$ -	$ -	$ -	$ -
5	**Total Rate Base**		$16,448.9	$ -	$16,415	$ -	$16,415

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$445.4	$ -	$445	$ -	$445
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$445.4	$ -	$445	$ -	$445
9	Working Capital Rate %	(1)	7.57%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$33.7		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Utility Income

Line No.	Particulars		Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$1,973.1	($1,973)	$ -	$ -	$ -
2	Other Revenue	(1)	$54.4	($54)	$ -	$ -	$ -
3	Total Operating Revenues		$2,027.5	($2,028)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$445	$ -	$445	$ -	$445
5	Depreciation/Amortization		$594	$ -	$594	$ -	$594
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($5)	$ -	($5)	$ -	($5)
9	Subtotal (lines 4 to 8)		$1,035	$ -	$1,035	$ -	$1,035
10	Deemed Interest Expense		$383	($383)	$0	($0)	$ -
11	Total Expenses (lines 9 to 10)		$1,417	($383)	$1,035	($0)	$1,035
12	**Utility income before income taxes**		$610	($1,645)	($1,035)	$0	($1,035)
13	Income taxes (grossed-up)		$61	$ -	$61	$ -	$61
14	**Utility net income**		$549	($1,645)	($1,096)	$0	($1,096)

Notes

Other Revenues / Revenue Offsets

Note		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$36		$ -		$ -
	Other Distribution Revenue	$37		$ -		$ -
	Other Income and Deductions	($19.3)		$ -		$ -
	Total Revenue Offsets	$54.4	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$610.2	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($377.1)	$ -	$ -
3	Taxable income	$233.1	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$45.1	$45	$45
6	Total taxes	$45.1	$45	$45
7	Gross-up of Income Taxes	$16.3	$16	$16
8	Grossed-up Income Taxes	$61.4	$61	$61
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$61.4	$61	$61
10	Other tax Credits	($0.3)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,211	4.04%	$372.5
2	Short-term Debt	4.00%	$658	1.56%	$10.3
3	**Total Debt**	60.00%	$9,869	3.88%	$382.7
	Equity				
4	Common Equity	40.00%	$6,580	8.34%	$548.7
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,580	8.34%	$548.7
7	**Total**	100.00%	$16,449	5.66%	$931.5
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$0
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$0
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$16,415	0.00%	$0
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.04%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$16,415	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$1,407		$1,408
2	Transmission Revenue	$ -	$1,973	$ -	$566	$ -	($1,408)
3	Other Operating Revenue Offsets - net	$54	$54	$ -	$ -	$ -	$ -
4	**Total Revenue**	$54	$2,027.5	$ -	$1,973.1	$ -	$ -
5	Operating Expenses	$1,035	$1,035	$1,035	$1,035	$1,035	$1,035
6	Deemed Interest Expense	$383	$383	$0	$0	$ -	$ -
8	**Total Cost and Expenses**	$1,417	$1,417	$1,035	$1,035	$1,035	$1,035
9	**Utility Income Before Income Taxes**	($1,363)	$610.2	($1,035)	$938	($1,035)	($1,034.6)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($377)	($377)	($377)	($377)	$ -	$ -
11	**Taxable Income**	($1,740)	$233.1	($1,412)	$561	($1,035)	($1,035)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$61.8	$ -	$148.8	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	($1,363)	$548.8	($1,034)	($1,096.1)	($1,035)	($1,096)
16	**Utility Rate Base**	$16,449	$16,449	$16,415	$16,415	$16,415	$16,415
17	Deemed Equity Portion of Rate Base	$6,580	$6,580	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	-20.71%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-29.05%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	-5.96%	5.66%	-6.30%	0.00%	-6.30%	0.00%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-11.62%	0.00%	-6.30%	0.00%	-6.30%	0.00%
24	Target Return on Equity	$549	$549	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)		$0	$1,034	$ -	$1,035	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$1,407 (1)		$1,408 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$445.4		$445		$445	
2	Amortization/Depreciation	$593.8		$594		$594	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$61.4		$61		$61	
6	Other Expenses	($4.6)		($5)		($5)	
7	Return						
	Deemed Interest Expense	$382.7		$0		$ -	
	Return on Deemed Equity	$548.7		($0)		$ -	
8	**Service Revenue Requirement (before Revenues)**	$2,027.5		$1,096		$1,096	
9	Revenue Offsets	$54.4		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,973.1		$1,096		$1,096	
11	Transmission revenue	$1,973.1		$ -		$ -	
12	Other revenue	$54.4		$ -		$ -	
13	**Total revenue**	$2,027.5		$ -		$ -	
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	$0.0	(1)	($1,096)	(1)	($1,096)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$2,028	$1,096	**($0)**	$1,096	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$1,407		$1,408	
Base Revenue Requirement (to be recovered from Rates)	$1,973	$1,096	**($0)**	$1,096	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,973	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** (1) Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 2,027.51**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year	Price Cap IR Period: 1	Price Cap IR Period: 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 931	5.66%	$ 16,449	$ 445	$ 34	$ 594	$ 61	$ 445	$ 2,028	$ 54	$ 1,973	$ -
1													

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Data Input [1]

		Initial Application	[2]	Adjustments	Application Update	[6]	Adjustments	Per Board Decision	
		($ millions)			($ millions)			($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$27,078			$ 27,078			$27,078	
	Accumulated Depreciation (average)	($9,719)	[5]		($9,719)			($9,719)	
	Allowance for Working Capital:								
	Controllable Expenses	$454			$ 454			$454	
	Cost of Power								
	Working Capital Rate (%)	7.70%	[9]			[9]			[9]
2	**Utility Income**								
	Operating Revenues:								
	Transmission Revenue at Current Rates								
	Transmission Revenue at Proposed Rates	$2,087							
	Other Revenue:								
	Specific Service Charges								
	Non-rate revenues	$36							
	Export Revenue Credits	$37							
	LVSG + Regulatory Balances	($20)							
	Total Revenue Offsets	$53.1	[7]						
	Operating Expenses:								
	OM+A Expenses	$454			454.35			$454	
	Depreciation/Amortization	$625			625.13			$625	
	Property taxes								
	Productivity adjustments	($7)			- 7.22			($7)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($349)	[3]						
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$61.05							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	($0.3)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)		[8]			[8]			[8]
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
		100.0%							
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.04%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$27,078.4	$ -	$27,078	$ -	$27,078
2	Accumulated Depreciation (average)	(2)	($9,719.2)	$ -	($9,719)	$ -	($9,719)
3	Net Fixed Assets (average)	(2)	$17,359.1	$ -	$17,359	$ -	$17,359
4	Allowance for Working Capital	(1)	$35.0	$ -	$ -	$ -	$ -
5	**Total Rate Base**		$17,394.1	$ -	$17,359	$ -	$17,359

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$454.3	$ -	$454	$ -	$454
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$454.3	$ -	$454	$ -	$454
9	Working Capital Rate %	(1)	7.70%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$35.0		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Utility Income

Line No.	Particulars		Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$2,087.2	($2,087)	$ -	$ -	$ -
2	Other Revenue	(1)	$53.1	($53)	$ -	$ -	$ -
3	Total Operating Revenues		$2,140.3	($2,140)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$454	$ -	$454	$ -	$454
5	Depreciation/Amortization		$625	$ -	$625	$ -	$625
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($7)	$ -	($7)	$ -	($7)
9	Subtotal (lines 4 to 8)		$1,072	$ -	$1,072	$ -	$1,072
10	Deemed Interest Expense		$405	($405)	$0	($0)	$ -
11	Total Expenses (lines 9 to 10)		$1,477	($405)	$1,072	($0)	$1,072
12	**Utility income before income taxes**		$663	($1,736)	($1,072)	$0	($1,072)
13	Income taxes (grossed-up)		$83	$ -	$83	$ -	$83
14	**Utility net income**		$580	($1,736)	($1,155)	$0	($1,155)

Notes

Other Revenues / Revenue Offsets

Note		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$36		$ -		$ -
	Other Distribution Revenue	$37		$ -		$ -
	Other Income and Deductions	($20.3)		$ -		$ -
	Total Revenue Offsets	$53.1	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Taxes/PILs

Line No.	Particulars	Application ($ millions)	Application Update ($ millions)	Per Board Decision ($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$663.3	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($348.7)	$ -	$ -
3	Taxable income	$314.7	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$61.0	$61	$61
6	Total taxes	$61.0	$61	$61
7	Gross-up of Income Taxes	$22.0	$22	$22
8	Grossed-up Income Taxes	$83.1	$83	$83
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$83.1	$83	$83
10	Other tax Credits	($0.3)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,741	4.04%	$393.86
2	Short-term Debt	4.00%	$696	1.56%	$10.85
3	**Total Debt**	60.00%	$10,436	3.88%	$404.71
	Equity				
4	Common Equity	40.00%	$6,958	8.34%	$580.27
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$6,958	8.34%	$580.27
7	**Total**	100.00%	$17,394	5.66%	$984.98
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$0
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$0
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$17,359	0.00%	$0
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.04%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$17,359	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$1,458		$1,459
2	Transmission Revenue	$ -	$2,087	$ -	$629	$ -	($1,459)
3	Other Operating Revenue Offsets - net	$53	$53	$ -	$ -	$ -	$ -
4	**Total Revenue**	$53	$2,140.3	$ -	$2,087.2	$ -	$ -
5	Operating Expenses	$1,072	$1,072	$1,072	$1,072	$1,072	$1,072
6	Deemed Interest Expense	$405	$405	$0	$0	$ -	$ -
8	**Total Cost and Expenses**	$1,477	$1,477	$1,072	$1,072	$1,072	$1,072
9	**Utility Income Before Income Taxes**	($1,424)	$663.3	($1,072)	$1,015	($1,072)	($1,072.3)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($349)	($349)	($349)	($349)	$ -	$ -
11	**Taxable Income**	($1,773)	$314.7	($1,421)	$666	($1,072)	($1,072)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$83.4	$ -	$176.5	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	($1,424)	$580.3	($1,072)	($1,155.3)	($1,072)	($1,155)
16	**Utility Rate Base**	$17,394	$17,394	$17,359	$17,359	$17,359	$17,359
17	Deemed Equity Portion of Rate Base	$6,958	$6,958	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	-20.46%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-28.80%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	-5.86%	5.66%	-6.17%	0.00%	-6.18%	0.00%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-11.52%	0.00%	-6.17%	0.00%	-6.18%	0.00%
24	Target Return on Equity	$580	$580	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)		($0)	$1,072	$ -	$1,072	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$1,458 (1)		$1,459 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Requirement

Line No.	Particulars	Application	Application Update	Per Board Decision
1	OM&A Expenses	$454.3	$454	$454
2	Amortization/Depreciation	$625.1	$625	$625
3	Property Taxes	$ -		
5	Income Taxes (Grossed up)	$83.1	$83	$83
6	Other Expenses	($7.2)	($7)	($7)
7	Return			
	Deemed Interest Expense	$404.7	$0	$ -
	Return on Deemed Equity	$580.3	($0)	$ -
8	**Service Revenue Requirement (before Revenues)**	$2,140.3	$1,155	$1,155
9	Revenue Offsets	$53.1	$ -	$ -
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$2,087.2	$1,155	$1,155
11	Transmission revenue	$2,087.2	$ -	$ -
12	Other revenue	$53.1	$ -	$ -
13	**Total revenue**	$2,140.3	$ -	$ -
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	($0.0) [1]	($1,155) [1]	($1,155) [1]

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% [2]	Per Board Decision	Δ% (2)
Service Revenue Requirement	$2,140	$1,155	**($0)**	$1,155	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$1,458		$1,459	
Base Revenue Requirement (to be recovered from Rates)	$2,087	$1,155	**($0)**	$1,155	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$2,087	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [(1)] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[(1)] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 2,140.28**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year	Price Cap IR Period 1	Price Cap IR Period 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates				Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate Rate	Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance: $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 985	5.66%	$ 17,394	$ 454	$ 35	$ 625	$ 83	$ 454	$ 2,140	$ 53	$ 2,087	$ -
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	*Transmission*
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Data Input (1)

		Initial Application	(2)	Adjustments	Application Update	(6)	Adjustments	Per Board Decision	
		($ millions)			($ millions)			($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$28,459			$ 28,459			$28,459	
	Accumulated Depreciation (average)	($10,238)	(5)		($10,238)			($10,238)	
	Allowance for Working Capital:								
	Controllable Expenses	$463			$ 463			$463	
	Cost of Power								
	Working Capital Rate (%)	7.62%	(9)			(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Transmission Revenue at Current Rates								
	Transmission Revenue at Proposed Rates	$2,166							
	Other Revenue:								
	Specific Service Charges								
	Non-rate revenues	$37							
	Export Revenue Credits	$37							
	LVSG + Regulatory Balances	($21)							
	Total Revenue Offsets	$54	(7)						
	Operating Expenses:								
	OM+A Expenses	$463			463.43			$463	
	Depreciation/Amortization	$647			647.32			$647	
	Property taxes								
	OProductivity adjustments	($10)			- 9.84			($10)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($374)	(3)						
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$61.99							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	($0.3)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
		100.0%							
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.04%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates				Revenue Reconciliation		
												Monthly Service Charge		Volumetric Rate				
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -
#			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance: $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
	Operating Revenues:						
1	Transmission Revenue (at Proposed Rates)		$2,165.5	($2,166)	$ -	$ -	$ -
2	Other Revenue	(1)	$53.6	($54)	$ -	$ -	$ -
3	Total Operating Revenues		$2,219.1	($2,219)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$463	$ -	$463	$ -	$463
5	Depreciation/Amortization		$647	$ -	$647	$ -	$647
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($10)	$ -	($10)	$ -	($10)
9	Subtotal (lines 4 to 8)		$1,101	$ -	$1,101	$ -	$1,101
10	Deemed Interest Expense		$425	($425)	$0	($0)	$ -
11	Total Expenses (lines 9 to 10)		$1,526	($425)	$1,101	($0)	$1,101
12	**Utility income before income taxes**		$693	($1,794)	($1,101)	$0	($1,101)
13	Income taxes (grossed-up)		$84	$ -	$84	$ -	$84
14	**Utility net income**		$609	($1,794)	($1,185)	$0	($1,185)

Notes

Other Revenues / Revenue Offsets

Note		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$37		$ -		$ -
	Other Distribution Revenue	$37		$ -		$ -
	Other Income and Deductions	($20.9)		$ -		$ -
	Total Revenue Offsets	$53.6	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$693.4	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($373.8)	$ -	$ -
3	Taxable income	$319.6	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$62.0	$62	$62
6	Total taxes	$62.0	$62	$62
7	Gross-up of Income Taxes	$22.4	$22	$22
8	Grossed-up Income Taxes	$84.3	$84	$84
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$84.3	$84	$84
10	Other tax Credits	($0.3)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Class Allocated Revenues

Notes

Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$10,223	4.04%	$413.4
2	Short-term Debt	4.00%	$730	1.56%	$11.4
3	**Total Debt**	60.00%	$10,954	3.88%	$424.8
	Equity				
4	Common Equity	40.00%	$7,302	8.34%	$609.0
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$7,302	8.34%	$609.0
7	**Total**	100.00%	$18,256	5.66%	$1,033.8
		Application Update			($ millions)
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$0
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$0
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$18,221	0.00%	$0
		Per Board Decision			($ millions)
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.04%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$18,221	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Deficiency/Sufficiency

(Not Applicable for Transmission)

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		$ -		$1,497		$1,498
2	Transmission Revenue	$ -	$2,166	$ -	$668	$ -	($1,498)
3	Other Operating Revenue Offsets - net	$54	$54	$ -	$ -	$ -	$ -
4	**Total Revenue**	$54	$2,219.1	$ -	$2,165.5	$ -	$ -
5	Operating Expenses	$1,101	$1,101	$1,101	$1,101	$1,101	$1,101
6	Deemed Interest Expense	$425	$425	$0	$0	$ -	$ -
8	**Total Cost and Expenses**	$1,526	$1,526	$1,101	$1,101	$1,101	$1,101
9	**Utility Income Before Income Taxes**	($1,472)	$693.4	($1,101)	$1,065	($1,101)	($1,100.9)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($374)	($374)	($374)	($374)	$ -	$ -
11	**Taxable Income**	($1,846)	$319.6	($1,475)	$691	($1,101)	($1,101)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$84.7	$ -	$183.1	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	($1,472)	$609.1	($1,101)	($1,185.3)	($1,101)	($1,185)
16	**Utility Rate Base**	$18,256	$18,256	$18,221	$18,221	$18,221	$18,221
17	Deemed Equity Portion of Rate Base	$7,302	$7,302	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	-20.15%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-28.49%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	-5.74%	5.66%	-6.04%	0.00%	-6.04%	0.00%
22	Requested Rate of Return on Rate Base	5.66%	5.66%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-11.40%	0.00%	-6.04%	0.00%	-6.04%	0.00%
24	Target Return on Equity	$609	$609	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)		$0	$1,101	$ -	$1,101	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	(1)		$1,497 (1)		$1,498 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Requirement

Line No.	Particulars	Application	Application Update	Per Board Decision
1	OM&A Expenses	$463.4	$463	$463
2	Amortization/Depreciation	$647.3	$647	$647
3	Property Taxes	$ -		
5	Income Taxes (Grossed up)	$84.3	$84	$84
6	Other Expenses	($9.8)	($10)	($10)
7	Return			
	Deemed Interest Expense	$424.8	$0	$ -
	Return on Deemed Equity	$609.0	($0)	$ -
8	**Service Revenue Requirement (before Revenues)**	$2,219.0	$1,185	$1,185
9	Revenue Offsets	$53.6	$ -	$ -
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$2,165.5	$1,185	$1,185
11	Transmission revenue	$2,165.5	$ -	$ -
12	Other revenue	$53.6	$ -	$ -
13	**Total revenue**	$2,219.1	$ -	$ -
14	**Difference (Total Revenue Less Revenue Requirement before Revenues)**	$0.0 (1)	($1,185) (1)	($1,185) (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$2,219	$1,185	**($0)**	$1,185	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$ -	$1,497		$1,498	
Base Revenue Requirement (to be recovered from Rates)	$2,165	$1,185	**($0)**	$1,185	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$2,166	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%
	Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.		**Service Revenue Requirement (from Sheet 9)**	**$ 2,219.05**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [(11)]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year	Price Cap IR Period: 1	Price Cap IR Period: 2	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:

	Customer Class From sheet 10. Load Forecast	Customer and Load Forecast Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed / Variable Splits [2] Percentage to be entered as a fraction between 0 and 1 Fixed	Variable	Transformer Ownership Allowance [1] ($)	Distribution Rates Monthly Service Charge Rate	No. of decimals	Volumetric Rate Rate		No. of decimals	Revenue Reconciliation MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2		/kWh	4	$ -	$ -	$ -
2			-	-	-												$ -	$ -	$ -
3			-	-	-												$ -	$ -	$ -
4			-	-	-												$ -	$ -	$ -
5			-	-	-												$ -	$ -	$ -
6			-	-	-												$ -	$ -	$ -
7			-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
9			-	-	-												$ -	$ -	$ -
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 1,034	5.66%	$ 18,256	$ 463	$ 35	$ 647	$ 84	$ 463	$ 2,219	$ 54	$ 2,165	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input [1]

		Initial Application	(2)	Adjustments	Application Update	(6)	Adjustments	Per Board Decision	
		($ millions)			($ millions)			($ millions)	
1	**Rate Base**								
	Gross Fixed Assets (average)	$14,813			$ 14,813			$14,813	
	Accumulated Depreciation (average)	($5,691)	(5)		($5,691)			($5,691)	
	Allowance for Working Capital:								
	Controllable Expenses	$603			$ 603			$603	
	Cost of Power	$3,423			$ 3,423			$3,423	
	Working Capital Rate (%)	6.20%	(9)			(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$1,666							
	Distribution Revenue at Proposed Rates	$1,586	(10)						
	Other Revenue:								
	Specific Service Charges								
	Late Payment Charges								
	Other Distribution Revenue	$46							
	Other Income and Deductions								
	Total Revenue Offsets	$46	(7)						
	Operating Expenses:								
	OM+A Expenses	$603			$ 603			$603	
	Depreciation/Amortization	$460			$ 460			$460	
	Property taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($208)	(3)						
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$27.33							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	(0.4)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
		100.0%							
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.07%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

(10) Distribution revenue at proposed rates is net of revenue offsets, in order to achieve comparability against distribution revenues at current rates, where the last approved rates are net of offsets

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
1	Gross Fixed Assets (average)	(2)	$14,813.3	$ -	$14,813	$ -	$14,813
2	Accumulated Depreciation (average)	(2)	($5,690.8)	$ -	($5,691)	$ -	($5,691)
3	Net Fixed Assets (average)	(2)	$9,122.5	$ -	$9,123	$ -	$9,123
4	Allowance for Working Capital	(1)	$249.5	($249)	$ -	$ -	$ -
5	**Total Rate Base**		$9,372.0	($249)	$9,123	$ -	$9,123

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$603.0	$ -	$603	$ -	$603
7	Cost of Power		$3,422.8	$ -	$3,423	$ -	$3,423
8	Working Capital Base		$4,025.8	$ -	$4,026	$ -	$4,026
9	Working Capital Rate %	(1)	6.20%	-6.20%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$249.5	($249)	$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
			($ millions)		($ millions)		($ millions)
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,586.0	($1,586)	$ -	$ -	$ -
2	Other Revenue	(1)	$46.4	($46)	$ -	$ -	$ -
3	Total Operating Revenues		$1,632.4	($1,632)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$603	$ -	$603	$ -	$603
5	Depreciation/Amortization		$460	$ -	$460	$ -	$460
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$1,063	$ -	$1,063	$ -	$1,063
10	Deemed Interest Expense		$219	($219)	$0	($0)	$ -
11	Total Expenses (lines 9 to 10)		$1,283	($219)	$1,063	($0)	$1,063
12	**Utility income before income taxes**		$349.9	($1,413)	($1,063)	$0	($1,063)
13	Income taxes (grossed-up)		$37	$ -	$37	$ -	$37
14	**Utility net income**		$312.7	($1,413)	($1,100)	$0	($1,100)

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$ -		$ -		$ -
	Other Distribution Revenue	$46		$ -		$ -
	Other Income and Deductions	$ -		$ -		$ -
	Total Revenue Offsets	$46.4	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$349.9	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($207.9)	$ -	$ -
3	Taxable income	$142.0	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$27.3	$27	$27
6	Total taxes	$27.3	$27	$27
7	Gross-up of Income Taxes	$9.9	$10	$10
8	Grossed-up Income Taxes	$37.2	$37	$37
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$37.2	$37	$37
10	Other tax Credits	($0.4)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($ millions) ($)
	Debt				
1	Long-term Debt	56.00%	$5,248	4.07%	$213.6
2	Short-term Debt	4.00%	$375	1.56%	$5.8
3	**Total Debt**	60.00%	$5,623	3.90%	$219.5
	Equity				
4	Common Equity	40.00%	$3,749	8.34%	$312.7
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,749	8.34%	$312.7
7	**Total**	100.00%	$9,372	5.68%	$532.1

Application Update

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($ millions) ($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$0
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$0
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$9,123	0.00%	$0

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($ millions) ($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.07%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$9,123	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
		($ millions)		($ millions)		($ millions)	
1	Revenue Deficiency from Below		($80)		($678)		$1,446
2	Distribution Revenue	$1,666	$1,666	$1,666	$2,264	$ -	($1,446)
3	Other Operating Revenue Offsets - net	$46	$46	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,712	$1,632.4	$1,666	$1,586.0	$ -	$ -
5	Operating Expenses	$1,063	$1,063	$1,063	$1,063	$1,063	$1,063
6	Deemed Interest Expense	$219	$219	$0	$0	$ -	$ -
8	**Total Cost and Expenses**	$1,283	$1,283	$1,063	$1,063	$1,063	$1,063
9	**Utility Income Before Income Taxes**	$430	$349.9	$603	$523	($1,063)	($1,063.1)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($208)	($208)	($208)	($208)	$ -	$ -
11	**Taxable Income**	$222	$142.0	$395	$315	($1,063)	($1,063)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$59	$37.6	$105	$83.5	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	$371	$312.7	$498	($1,100.3)	($1,063)	($1,100)
16	**Utility Rate Base**	$9,372	$9,372	$9,123	$9,123	$9,123	$9,123
17	Deemed Equity Portion of Rate Base	$3,749	$3,749	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	9.90%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	1.56%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	6.30%	5.68%	5.46%	0.00%	-11.65%	0.00%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	0.63%	0.00%	5.46%	0.00%	-11.65%	0.00%
24	Target Return on Equity	$313	$313	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	($59)	$0	($498)	$ -	$1,063	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	($80) (1)		($678) (1)		$1,446 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$603.0		$603		$603	
2	Amortization/Depreciation	$460.1		$460		$460	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$37.2		$37		$37	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$219.5		$0		$ -	
	Return on Deemed Equity	$312.7		($0)		$ -	
8	**Service Revenue Requirement (before Revenues)**	$1,632.4		$1,100		$1,100	
9	Revenue Offsets	$46.4		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,586.0		$1,100		$1,100	
11	Distribution revenue	$1,586.0		$ -		$ -	
12	Other revenue	$46.4		$ -		$ -	
13	**Total revenue**	$1,632.4		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0	(1)	($1,100)	(1)	($1,100)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,632	$1,100	($0)	$1,100	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	($80)	($678)	$8	$1,446	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,586	$1,100	($0)	$1,100	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	($80)	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class (3) From Sheet 10. Load Forecast	Costs Allocated from Previous Study (1)	%	Allocated Class Revenue Requirement (1) (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,632.38**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
			1	2	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance: $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

1. Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2. The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 532	5.68%	$ 9,372	$ 4,026	$ 249	$ 460	$ 37	$ 603	$ 1,632	$ 46	$ 1,586	-$ 80

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Data Input [1]

		Initial Application [2]	Adjustments	Application Update [6]	Adjustments	Per Board Decision
		($ millions)		($ millions)		($ millions)
1	**Rate Base**					
	Gross Fixed Assets (average)	$15,634.2		$ 15,634		$15,634
	Accumulated Depreciation (average)	($5,923.7)		($5,924)		($5,924)
	Allowance for Working Capital:					
	Controllable Expenses	$614		$ 614		$614
	Cost of Power	$3,423		$ 3,423		$3,423
	Working Capital Rate (%)	6.25%		(9)		(9)
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$1,594				
	Distribution Revenue at Proposed Rates	$1,665				
	Other Revenue:					
	Specific Service Charges					
	Late Payment Charges					
	Other Distribution Revenue	$46				
	Other Income and Deductions					
	Total Revenue Offsets	$46				
	Operating Expenses:					
	OM+A Expenses	$614		$ 614		$614
	Depreciation/Amortization	$481		$ 481		$481
	Property taxes					
	Productivity adjustments	($5)		($5)		($5)
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($179)				
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$40.1				
	Income taxes (grossed up)					
	Federal tax (%)	15.00%				
	Provincial tax (%)	11.50%				
	Income Tax Credits	($0.4)				
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%				
	Prefered Shares Capitalization Ratio (%)					
	Cost of Capital					
	Long-term debt Cost Rate (%)	4.07%				
	Short-term debt Cost Rate (%)	1.56%				
	Common Equity Cost Rate (%)	8.34%				
	Prefered Shares Cost Rate (%)					

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
1	Gross Fixed Assets (average)	(2)	$15,634.2	$ -	$15,634	$ -	$15,634
2	Accumulated Depreciation (average)	(2)	($5,923.7)	$ -	($5,924)	$ -	($5,924)
3	Net Fixed Assets (average)	(2)	$9,710.5	$ -	$9,710	$ -	$9,710
4	Allowance for Working Capital	(1)	$252.4		$ -	$ -	$ -
5	**Total Rate Base**		$9,962.9	$ -	$9,710	$ -	$9,710

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$614	$ -	$614	$ -	$614
7	Cost of Power		$3,423	$ -	$3,423	$ -	$3,423
8	Working Capital Base		$4,037	$ -	$4,037	$ -	$4,037
9	Working Capital Rate %	(1)	6.25%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$252.4		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Utility Income

Line No.	Particulars	Initial Application ($ millions)	Adjustments	Application Update ($ millions)	Adjustments	Per Board Decision ($ millions)
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$1,664.84	($1,665)	$ -	$ -	$ -
2	Other Revenue (1)	$46.46	($46)	$ -	$ -	$ -
3	Total Operating Revenues	$1,711.29	($1,711)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$614.5	$ -	$614	$ -	$614
5	Depreciation/Amortization	$481.3	$ -	$481	$ -	$481
6	Property taxes	$ -	$ -		$ -	
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	($4.7)	$ -	($5)	$ -	($5)
9	Subtotal (lines 4 to 8)	$1,091.1	$ -	$1,091	$ -	$1,091
10	Deemed Interest Expense	$233.3	($233)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)	$1,324.3	($233)	$1,091	$ -	$1,091
12	**Utility income before income taxes**	$386.9	($1,478)	($1,091)	$ -	($1,091)
13	Income taxes (grossed-up)	$54.6	$ -	$55	$ -	$55
14	**Utility net income**	$332.4	($1,478)	($1,146)	$ -	($1,146)

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
Specific Service Charges	$ -	$ -	$ -		$ -
Late Payment Charges	$ -	$ -	$ -		$ -
Other Distribution Revenue	$46	$ -	$ -		$ -
Other Income and Deductions	$ -	$ -	$ -		$ -
Total Revenue Offsets	$46	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
		($ millions)	($ millions)	($ millions)
	Determination of Taxable Income			
1	Utility net income before taxes	$386.9	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($179.3)	$ -	$ -
3	Taxable income	$207.6	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$40.1	$40	$40
6	Total taxes	$40.1	$40	$40
7	Gross-up of Income Taxes	$14.5	$14	$14
8	Grossed-up Income Taxes	$54.6	$55	$55
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$54.6	$55	$55
10	Other tax Credits	($0.4)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($ millions) ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$5,579.2	4.07%	$227.1
2	Short-term Debt	4.00%	$398.5	1.56%	$6.2
3	**Total Debt**	60.00%	$5,977.7	3.90%	$233.3
	Equity				
4	Common Equity	40.00%	$3,985.2	8.34%	$332.4
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,985.2	8.34%	$332.4
7	**Total**	100.00%	$9,962.9	5.68%	$565.6
	Application Update				
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$9,710	0.00%	$ -
	Per Board Decision				
	Debt				
8	Long-term Debt	0.00%	$ -	4.07%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$9,710	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$71		($568)		$1,484
2	Distribution Revenue	$1,594	$1,594	$1,594	$2,233	$ -	($1,484)
3	Other Operating Revenue Offsets - net	$46	$46	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,640	$1,711.3	$1,594	$1,665	$ -	$ -
5	Operating Expenses	$1,091	$1,091	$1,091	$1,091	$1,091	$1,091
6	Deemed Interest Expense	$233	$233	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$1,324	$1,324	$1,091	$1,091	$1,091	$1,091
9	**Utility Income Before Income Taxes**	$316	$386.9	$503	$574	($1,091)	($1,091)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($179)	($179)	($179)	($179)	$ -	$ -
11	**Taxable Income**	$137	$207.6	$323	$394	($1,091)	($1,091)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$36	$55.0	$86	$105	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	$280	$332	$418	($1,146)	($1,091)	($1,146)
16	**Utility Rate Base**	$9,963	$9,963	$9,710	$9,710	$9,710	$9,710
17	Deemed Equity Portion of Rate Base	$3,985	$3,985	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.03%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.31%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.15%	5.68%	4.30%	0.00%	-11.24%	0.00%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.52%	0.00%	4.30%	0.00%	-11.24%	0.00%
24	Target Return on Equity	$332	$332	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$52	$0	($418)	$ -	$1,091	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$71 [1]		($568) [1]		$1,484 [1]	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
		($ millions)		($ millions)		($ millions)	
1	OM&A Expenses	$614.5		$614		$614	
2	Amortization/Depreciation	$481.3		$481		$481	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$54.6		$55		$55	
6	Other Expenses	($4.7)		($5)		($5)	
7	Return						
	Deemed Interest Expense	$233.3		$ -		$ -	
	Return on Deemed Equity	$332.4		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$1,711.3		$1,146		$1,146	
9	Revenue Offsets	$46.5		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,664.8		$1,146		$1,146	
11	Distribution revenue	$1,664.8		$ -		$ -	
12	Other revenue	$46.5		$ -		$ -	
13	**Total revenue**	$1,711.3		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0	(1)	($1,146)	(1)	($1,146)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,711.3	$1,146	($0)	$1,146	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$71	($568)	($9)	$1,484	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,664.8	$1,146	($0)	$1,146	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$71	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.

Service Revenue Requirement (from Sheet 9) **$ 1,711.29**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates				Revenue Reconciliation		
	From sheet 10. Load Forecast					From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate				
	Customer Class	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate	No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	-	-	-								2	/kWh	4	$ -	$ -	$ -
2			-	-	-											$ -	$ -	$ -
3			-	-	-											$ -	$ -	$ -
4			-	-	-											$ -	$ -	$ -
5			-	-	-											$ -	$ -	$ -
6			-	-	-											$ -	$ -	$ -
7			-	-	-											$ -	$ -	$ -
8			-	-	-											$ -	$ -	$ -
9			-	-	-											$ -	$ -	$ -
10			-	-	-											$ -	$ -	$ -
11			-	-	-											$ -	$ -	$ -
12			-	-	-											$ -	$ -	$ -
13			-	-	-											$ -	$ -	$ -
14			-	-	-											$ -	$ -	$ -
15			-	-	-											$ -	$ -	$ -
16			-	-	-											$ -	$ -	$ -
17			-	-	-											$ -	$ -	$ -
18			-	-	-											$ -	$ -	$ -
19			-	-	-											$ -	$ -	$ -
20			-	-	-											$ -	$ -	$ -

Total Transformer Ownership Allowance $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
	$ -
% Difference	

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 566	5.68%	$ 9,963	$ 4,037	$ 252	$ 481	$ 55	$ 614	$ 1,711	$ 46	$ 1,665	$ 71
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Data Input (1)

		Initial Application	(2)	Adjustments		Application Update	(6)	Adjustments		Per Board Decision	
1	**Rate Base**										
	Gross Fixed Assets (average)	$16,558				$ 16,558				$16,558	
	Accumulated Depreciation (average)	($6,171)				($6,171)				($6,171)	
	Allowance for Working Capital:										
	Controllable Expenses	$626				$ 626				$626	
	Cost of Power	$3,419				$ 3,419				$3,419	
	Working Capital Rate (%)	6.30%					(9)				(9)
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$1,673									
	Distribution Revenue at Proposed Rates	$1,739									
	Other Revenue:										
	Specific Service Charges										
	Late Payment Charges										
	Other Distribution Revenue	$47									
	Other Income and Deductions										
	Total Revenue Offsets	$46.5									
	Operating Expenses:										
	OM+A Expenses	$626				$ 626				$626	
	Depreciation/Amortization	$522				$ 522				$522	
	Property taxes										
	Productivity adjustments	($10)				($10)				($10)	
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	($236)									
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$31.1									
	Income taxes (grossed up)										
	Federal tax (%)	15.00%									
	Provincial tax (%)	11.50%									
	Income Tax Credits	($0.4)									
4	**Capitalization/Cost of Capital**										
	Capital Structure:										
	Long-term debt Capitalization Ratio (%)	56.0%									
	Short-term debt Capitalization Ratio (%)	4.0%					(8)				(8)
	Common Equity Capitalization Ratio (%)	40.0%									
	Prefered Shares Capitalization Ratio (%)										
	Cost of Capital										
	Long-term debt Cost Rate (%)	4.07%									
	Short-term debt Cost Rate (%)	1.56%									
	Common Equity Cost Rate (%)	8.34%									
	Prefered Shares Cost Rate (%)										

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$16,557.7	$ -	$16,558	$ -	$16,558
2	Accumulated Depreciation (average)	(2)	($6,171.4)	$ -	($6,171)	$ -	($6,171)
3	Net Fixed Assets (average)	(2)	$10,386.3	$ -	$10,386	$ -	$10,386
4	Allowance for Working Capital	(1)	$254.9		$ -	$ -	$ -
5	**Total Rate Base**		$10,641.2	$ -	$10,386	$ -	$10,386

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$626	$ -	$626	$ -	$626
7	Cost of Power		$3,419	$ -	$3,419	$ -	$3,419
8	Working Capital Base		$4,046	$ -	$4,046	$ -	$4,046
9	Working Capital Rate %	(1)	6.30%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$254.9		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,738.5	($1,739)	$ -	$ -	$ -
2	Other Revenue	(1)	$46.5	($47)	$ -	$ -	$ -
3	Total Operating Revenues		$1,785.1	($1,785)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$626.1	$ -	$626	$ -	$626
5	Depreciation/Amortization		$522.0	$ -	$522	$ -	$522
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($9.6)	$ -	($10)	$ -	($10)
9	Subtotal (lines 4 to 8)		$1,138.5	$ -	$1,139	$ -	$1,139
10	Deemed Interest Expense		$249.2	($249)	$0	($0)	$ -
11	Total Expenses (lines 9 to 10)		$1,387.7	($249)	$1,139	($0)	$1,139
12	**Utility income before income taxes**		$397.4	($1,536)	($1,139)	$0	($1,139)
13	Income taxes (grossed-up)		$42.4	$ -	$42	$ -	$42
14	**Utility net income**		$355.0	($1,536)	($1,181)	$0	($1,181)

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -	$ -	$ -		$ -
	Late Payment Charges	$ -	$ -	$ -		$ -
	Other Distribution Revenue	$47	$ -	$ -		$ -
	Other Income and Deductions	$ -	$ -	$ -		$ -
	Total Revenue Offsets	$46.5	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$397.4	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($235.8)	$ -	$ -
3	Taxable income	$161.6	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$31.1	$31	$31
6	Total taxes	$31.1	$31	$31
7	Gross-up of Income Taxes	$11.2	$11	$11
8	Grossed-up Income Taxes	$42.4	$42	$42
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$42.4	$42	$42
10	Other tax Credits	($0.4)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
		Initial Application			
	Debt				
1	Long-term Debt	56.00%	$5,959.1	4.07%	$242.5
2	Short-term Debt	4.00%	$425.6	1.56%	$6.6
3	**Total Debt**	60.00%	$6,384.7	3.90%	$249.2
	Equity				
4	Common Equity	40.00%	$4,256.5	8.34%	$355.0
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,256.5	8.34%	$355.0
7	**Total**	100.00%	$10,641.2	5.68%	$604.16
		Application Update			
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$0
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$0
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$10,386	0.00%	$0
		Per Board Decision			
	Debt				
8	Long-term Debt	0.00%	$ -	4.07%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$10,386	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Application Update		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$65		($620)		$1,549
2	Distribution Revenue	$1,673	$1,673	$1,673	$2,359	$ -	($1,549)
3	Other Operating Revenue Offsets - net	$47	$47	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,720	$1,785.1	$1,673	$1,739	$ -	$ -
5	Operating Expenses	$1,139	$1,139	$1,139	$1,139	$1,139	$1,139
6	Deemed Interest Expense	$249	$249	$0	$0	$ -	$ -
8	**Total Cost and Expenses**	$1,388	$1,388	$1,139	$1,139	$1,139	$1,139
9	**Utility Income Before Income Taxes**	$332	$397.4	$535	$600	($1,139)	($1,139)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($236)	($236)	($236)	($236)	$ -	$ -
11	**Taxable Income**	$96	$161.6	$299	$364	($1,139)	($1,139)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$25	$42.8	$79	$97	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	$307	$355	$456	($1,181)	($1,139)	($1,181)
16	**Utility Rate Base**	$10,641	$10,641	$10,386	$10,386	$10,386	$10,386
17	Deemed Equity Portion of Rate Base	$4,256	$4,256	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.21%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.13%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.23%	5.68%	4.39%	0.00%	-10.96%	0.00%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.45%	0.00%	4.39%	0.00%	-10.96%	0.00%
24	Target Return on Equity	$355	$355	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$48	$0	($456)	$ -	$1,139	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$65 (1)		($620) (1)		$1,549 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Requirement

Line No.	Particulars	Application	Application Update	Per Board Decision
1	OM&A Expenses	$626.1	$626	$626
2	Amortization/Depreciation	$522.0	$522	$522
3	Property Taxes	$ -		
5	Income Taxes (Grossed up)	$42.4	$42	$42
6	Other Expenses	($9.6)	($10)	($10)
7	Return			
	Deemed Interest Expense	$249.2	$0	$ -
	Return on Deemed Equity	$355.0	($0)	$ -
8	**Service Revenue Requirement (before Revenues)**	$1,785.1	$1,181	$1,181
9	Revenue Offsets	$46.5	$ -	$ -
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,738.5	$1,181	$1,181
11	Distribution revenue	$1,738.5	$ -	$ -
12	Other revenue	$46.5	$ -	$ -
13	**Total revenue**	$1,785.1	$ -	$ -
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0 (1)	($1,181) (1)	($1,181) (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,785.1	$1,181	($0)	$1,181	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$65	($620)	($10)	$1,549	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,738.5	$1,181	($0)	$1,181	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$65	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%
	Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.		**Service Revenue Requirement (from Sheet 9)**	**$ 1,785.08**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2018	Price Cap IR Period 2019	Price Cap IR Period 2020	Policy Range
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates					Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge: Rate	Monthly Service Charge: No. of decimals	Volumetric Rate: Rate		Volumetric Rate: No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2		/kWh	4	$ -	$ -	$ -
2			-	-	-												$ -	$ -	$ -
3			-	-	-												$ -	$ -	$ -
4			-	-	-												$ -	$ -	$ -
5			-	-	-												$ -	$ -	$ -
6			-	-	-												$ -	$ -	$ -
7			-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
9			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance: $ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 604	5.68%	$ 10,641	$ 4,046	$ 255	$ 522	$ 42	$ 626	$ 1,785	$ 47	$ 1,739	$ 65
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Data Input [1]

		Initial Application	(2)	Adjustments	Application Update	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$17,495			$ 17,495			$17,495	
	Accumulated Depreciation (average)	($6,451)			($6,451)			($6,451)	
	Allowance for Working Capital:								
	Controllable Expenses	$638			$ 638			$638	
	Cost of Power	$3,419			$ 3,419			$3,419	
	Working Capital Rate (%)	6.36%				(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$1,747							
	Distribution Revenue at Proposed Rates	$1,835							
	Other Revenue:								
	Specific Service Charges								
	Late Payment Charges								
	Other Distribution Revenue	$46							
	Other Income and Deductions								
	Total Revenue Offsets	$46							
	Operating Expenses:								
	OM+A Expenses	$638			$ 638			$638	
	Depreciation/Amortization	$557			$ 557			$557	
	Property taxes								
	Productivity adjustments	($15)			($15)			($15)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($211)							
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$43.5							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	($0.4)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)	4.0%				(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.07%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$17,495.0	$ -	$17,495	$ -	$17,495
2	Accumulated Depreciation (average)	(2)	($6,451.2)	$ -	($6,451)	$ -	($6,451)
3	Net Fixed Assets (average)	(2)	$11,043.8	$ -	$11,044	$ -	$11,044
4	Allowance for Working Capital	(1)	$258.0		$ -	$ -	$ -
5	**Total Rate Base**		$11,301.8		$11,044	$ -	$11,044

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$638	$ -	$638	$ -	$638
7	Cost of Power		$3,419	$ -	$3,419	$ -	$3,419
8	Working Capital Base		$4,057	$ -	$4,057	$ -	$4,057
9	Working Capital Rate %	(1)	6.36%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$258.0	($258)	$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,835.1	($1,835)	$ -	$ -	$ -
2	Other Revenue	(1)	$46.0	($46)	$ -	$ -	$ -
3	Total Operating Revenues		$1,881.1	($1,881)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$638.0	$ -	$638	$ -	$638
5	Depreciation/Amortization		$557.3	$ -	$557	$ -	$557
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($15.0)	$ -	($15)	$ -	($15)
9	Subtotal (lines 4 to 8)		$1,180.3	$ -	$1,180	$ -	$1,180
10	Deemed Interest Expense		$264.6	($265)	($0)	$0	$ -
11	Total Expenses (lines 9 to 10)		$1,444.9	($265)	$1,180	$0	$1,180
12	**Utility income before income taxes**		$436.2	($1,616)	($1,180)	($0)	($1,180)
13	Income taxes (grossed-up)		$59.2	$ -	$59	$ -	$59
14	**Utility net income**		$377.0	($1,616)	($1,239)	($0)	($1,239)

Notes

Other Revenues / Revenue Offsets

Note		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -	$ -	$ -		$ -
	Late Payment Charges	$ -	$ -	$ -		$ -
	Other Distribution Revenue	$46	$ -	$ -		$ -
	Other Income and Deductions	$ -	$ -	$ -		$ -
	Total Revenue Offsets	$46.0	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$436.2	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($211.2)	$ -	$ -
3	Taxable income	$225.0	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$43.5	$43	$43
6	Total taxes	$43.5	$43	$43
7	Gross-up of Income Taxes	$15.7	$16	$16
8	Grossed-up Income Taxes	$59.2	$59	$59
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$59.2	$59	$59
10	Other tax Credits	($0.4)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$6,329.0	4.07%	$257.6
2	Short-term Debt	4.00%	$452.1	1.56%	$7.0
3	**Total Debt**	60.00%	$6,781.1	3.90%	$264.6
	Equity				
4	Common Equity	40.00%	$4,520.7	8.34%	$377.0
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,520.7	8.34%	$377.0
7	**Total**	100.00%	$11,301.8	5.68%	$641.7
	Application Update				
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	($0)
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	($0)
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$11,044	0.00%	($0)
	Per Board Decision				
	Debt				
8	Long-term Debt	0.00%	$ -	4.07%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$11,044	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Deficiency/Sufficiency

		Initial Application		Application Update		Per Board Decision	
Line No.	**Particulars**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**
1	Revenue Deficiency from Below		$89		($643)		$1,606
2	Distribution Revenue	$1,747	$1,747	$1,747	$2,478	$ -	($1,606)
3	Other Operating Revenue Offsets - net	$46	$46	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,793	$1,881.1	$1,747	$1,835	$ -	$ -
5	Operating Expenses	$1,180	$1,180	$1,180	$1,180	$1,180	$1,180
6	Deemed Interest Expense	$265	$265	($0)	($0)	$ -	$ -
8	**Total Cost and Expenses**	$1,445	$1,445	$1,180	$1,180	$1,180	$1,180
9	**Utility Income Before Income Taxes**	$348	$436.2	$566	$655	($1,180)	($1,180)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($211)	($211)	($211)	($211)	$ -	$ -
11	**Taxable Income**	$136	$225.0	$355	$444	($1,180)	($1,180)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$36	$59.6	$94	$118	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	$312	$377	$473	($1,239)	($1,180)	($1,239)
16	**Utility Rate Base**	$11,302	$11,302	$11,044	$11,044	$11,044	$11,044
17	Deemed Equity Portion of Rate Base	$4,521	$4,521	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	6.90%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.44%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.10%	5.68%	4.28%	0.00%	-10.69%	0.00%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.58%	0.00%	4.28%	0.00%	-10.69%	0.00%
24	Target Return on Equity	$377	$377	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$65	$0	($473)	$ -	$1,180	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$89 (1)		($643) (1)		$1,606 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$638.0		$638		$638	
2	Amortization/Depreciation	$557.3		$557		$557	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$59.2		$59		$59	
6	Other Expenses	($15.0)		($15)		($15)	
7	Return						
	Deemed Interest Expense	$264.6		($0)		$ -	
	Return on Deemed Equity	$377.0		($0)		$ -	
8	**Service Revenue Requirement (before Revenues)**	$1,881.1		$1,239		$1,239	
9	Revenue Offsets	$46.0		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,835.1		$1,239		$1,239	
11	Distribution revenue	$1,835.1		$ -		$ -	
12	Other revenue	$46.0		$ -		$ -	
13	**Total revenue**	$1,881.1		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0.0	(1)	($1,239)	(1)	($1,239)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,881.1	$1,239	($0)	$1,239	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$89	($643)	($8)	$1,606	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,835.1	$1,239	($0)	$1,239	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$89	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	**$ -**	0.00%
	Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.		**Service Revenue Requirement (from Sheet 9)**	**$ 1,881.14**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [(11)]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	**2019**	**2020**	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2026 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Revenue Requirement Workform (RRWF) for 2026 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)
1	Residential	kWh	-	-	-						
2			-	-	-						
3			-	-	-						
4			-	-	-						
5			-	-	-						
6			-	-	-						
7			-	-	-						
8			-	-	-						
9			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
#			-	-	-						
										Total Transformer Ownership Allowance	$ -

	Distribution Rates					Revenue Reconciliation		
	Monthly Service Charge		Volumetric Rate					
	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1		2		/kWh	4	$ -	$ -	$ -
2						$ -	$ -	$ -
3						$ -	$ -	$ -
4						$ -	$ -	$ -
5						$ -	$ -	$ -
6						$ -	$ -	$ -
7						$ -	$ -	$ -
8						$ -	$ -	$ -
9						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
#						$ -	$ -	$ -
						Total Distribution Revenues		$ -
						Base Revenue Requirement		$ -
						Difference		$ -
						% Difference		

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 642	5.68%	$ 11,302	$ 4,057	$ 258	$ 557	$ 59	$ 638	$ 1,881	$ 46	$ 1,835	$ 89
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Version 7.02

Utility Name	Hydro One Networks Inc.
Service Territory	
Assigned EB Number	EB-2021-0110
Name and Title	
Phone Number	
Email Address	

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Data Input [1]

		Initial Application	(2)	Adjustments	Application Update	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$18,396			$ 18,396			$18,396	
	Accumulated Depreciation (average)	($6,777)			($6,777)			($6,777)	
	Allowance for Working Capital:								
	Controllable Expenses	$650			$ 650			$650	
	Cost of Power	$3,418			$ 3,418			$3,418	
	Working Capital Rate (%)	6.42%				(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$1,843							
	Distribution Revenue at Proposed Rates	$1,919							
	Other Revenue:								
	Specific Service Charges								
	Late Payment Charges								
	Other Distribution Revenue	$46							
	Other Income and Deductions								
	Total Revenue Offsets	$46							
	Operating Expenses:								
	OM+A Expenses	$650			$ 650			$650	
	Depreciation/Amortization	$592			$ 592			$592	
	Property taxes								
	Productivity adjustments	($21)			($21)			($21)	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($204)							
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$50.5							
	Income taxes (grossed up)								
	Federal tax (%)	15.00%							
	Provincial tax (%)	11.50%							
	Income Tax Credits	($0.4)							
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%							
	Short-term debt Capitalization Ratio (%)	4.0%				(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%							
	Prefered Shares Capitalization Ratio (%)								
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.07%							
	Short-term debt Cost Rate (%)	1.56%							
	Common Equity Cost Rate (%)	8.34%							
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$18,396.2	$ -	$18,396	$ -	$18,396
2	Accumulated Depreciation (average)	(2)	($6,776.8)	$ -	($6,777)	$ -	($6,777)
3	Net Fixed Assets (average)	(2)	$11,619.5	$ -	$11,619	$ -	$11,619
4	Allowance for Working Capital	(1)	$261.0	$ -	$ -	$ -	$ -
5	**Total Rate Base**		$11,880.5	$ -	$11,619	$ -	$11,619

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
6	Controllable Expenses		$650	$ -	$650	$ -	$650
7	Cost of Power		$3,418	$ -	$3,418	$ -	$3,418
8	Working Capital Base		$4,068	$ -	$4,068	$ -	$4,068
9	Working Capital Rate %	(1)	6.42%		0.00%	0.00%	0.00%
10	Working Capital Allowance		$261.0		$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,918.9		$ -	$ -	$ -
2	Other Revenue	(1)	$46.1	($46)	$ -	$ -	$ -
3	Total Operating Revenues		$1,965.0	($46)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$650.2	$ -	$650	$ -	$650
5	Depreciation/Amortization		$592.3	$ -	$592	$ -	$592
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		($20.7)	$ -	($21)	$ -	($21)
9	Subtotal (lines 4 to 8)		$1,221.7	$ -	$1,222	$ -	$1,222
10	Deemed Interest Expense		$278.2		($0)	$0	$ -
11	Total Expenses (lines 9 to 10)		$1,499.9		$1,222	$0	$1,222
12	**Utility income before income taxes**		$465.0	($46)	($1,222)	($0)	($1,222)
13	Income taxes (grossed-up)		$68.7	$ -	$69	$ -	$69
14	**Utility net income**		$396.3	($46)	($1,290)	($0)	($1,290)

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Application Update	Adjustments	Per Board Decision
(1)	Specific Service Charges	$ -	$ -	$ -		$ -
	Late Payment Charges	$ -	$ -	$ -		$ -
	Other Distribution Revenue	$46	$ -	$ -		$ -
	Other Income and Deductions	$ -	$ -	$ -		$ -
	Total Revenue Offsets	$46.1	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Taxes/PILs

Line No.	Particulars	Application	Application Update	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$465.0	($0)	$ -
2	Adjustments required to arrive at taxable utility income	($204.1)	$ -	$ -
3	Taxable income	$260.9	($0)	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$50.5	$50	$50
6	Total taxes	$50.5	$50	$50
7	Gross-up of Income Taxes	$18.2	$18	$18
8	Grossed-up Income Taxes	$68.7	$69	$69
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$68.7	$69	$69
10	Other tax Credits	($0.4)	($0)	($0)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$6,653.1	4.07%	$270.8
2	Short-term Debt	4.00%	$475.2	1.56%	$7.4
3	**Total Debt**	60.00%	$7,128.3	3.90%	$278.2
	Equity				
4	Common Equity	40.00%	$4,752.2	8.34%	$396.3
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,752.2	8.34%	$396.3
7	**Total**	100.00%	$11,880.5	5.68%	$674.5
	Application Update				
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	($0)
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	($0)
	Equity				
4	Common Equity	0.00%	$ -	0.00%	($0)
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	($0)
7	**Total**	0.00%	$11,619	0.00%	($0)
	Per Board Decision				
	Debt				
8	Long-term Debt	0.00%	$ -	4.07%	$ -
9	Short-term Debt	0.00%	$ -	1.56%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.34%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$11,619	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Application Update: At Current Approved Rates	Application Update: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$75		($696)		$1,662
2	Distribution Revenue	$1,843	$1,843	$1,843	$2,615	$ -	($1,662)
3	Other Operating Revenue Offsets - net	$46	$46	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,889	$1,965.0	$1,843	$1,919	$ -	$ -
5	Operating Expenses	$1,222	$1,222	$1,222	$1,221.731	$1,222	$1,222
6	Deemed Interest Expense	$278	$278	($0)	($0)	$ -	$ -
8	**Total Cost and Expenses**	$1,500	$1,500	$1,222	$1,222	$1,222	$1,222
9	**Utility Income Before Income Taxes**	$390	$465.0	$622	$697	($1,222)	($1,222)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($204)	($204)	($204)	($204)	$ -	$ -
11	**Taxable Income**	$185	$260.9	$418	$493	($1,222)	($1,222)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$49	$69.1	$111	$131	$ -	$ -
14	**Income Tax Credits**	($0)	($0)	($0)	($0)	$ -	$ -
15	**Utility Net Income**	$341	$396	$512	($1,290)	($1,222)	($1,290)
16	**Utility Rate Base**	$11,880	$11,880	$11,619	$11,619	$11,619	$11,619
17	Deemed Equity Portion of Rate Base	$4,752	$4,752	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.17%	8.34%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.34%	8.34%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.17%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.21%	5.68%	4.40%	0.00%	-10.51%	0.00%
22	Requested Rate of Return on Rate Base	5.68%	5.68%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.47%	0.00%	4.40%	0.00%	-10.51%	0.00%
24	Target Return on Equity	$396	$396	($0)	($0)	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$55	($0)	($512)	$ -	$1,222	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$75 (1)		($696) (1)		$1,662 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Revenue Requirement

Line No.	Particulars	Application		Application Update		Per Board Decision	
1	OM&A Expenses	$650.2		$650		$650	
2	Amortization/Depreciation	$592.3		$592		$592	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$68.7		$69		$69	
6	Other Expenses	($20.7)		($21)		($21)	
7	Return						
	Deemed Interest Expense	$278.2		($0)		$ -	
	Return on Deemed Equity	$396.3		($0)		$ -	
8	**Service Revenue Requirement (before Revenues)**	$1,965.0		$1,290		$1,290	
9	Revenue Offsets	$46.1		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,918.9		$1,290		$1,290	
11	Distribution revenue	$1,918.9		$ -		$ -	
12	Other revenue	$46.1		$ -		$ -	
13	**Total revenue**	$1,965.0		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0.0)	(1)	($1,290)	(1)	($1,290)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Application Update	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,965	$1,290	($0)	$1,290	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$75	($696)	($10)	$1,662	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,919	$1,290	($0)	$1,290	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$75	$ -	($1)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application			Application Update			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual	**Customer / Connections** Test Year average or mid-	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		-							

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	0.00%	$ -	0.00%
	Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.		**Service Revenue Requirement (from Sheet 9)**	**$ 1,964.96**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ -	$ -	$ -	$ -

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
			1	2	
1	Residential				85 - 115
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential - Urban Density Class	
Customers	-
kWh	-

Proposed Residential Class Specific Revenue Requirement[1]	$ -

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		-		
Variable		-		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2027 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates					Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate					
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	-	-	-								2		/kWh	4	$ -	$ -	$ -
2			-	-	-												$ -	$ -	$ -
3			-	-	-												$ -	$ -	$ -
4			-	-	-												$ -	$ -	$ -
5			-	-	-												$ -	$ -	$ -
6			-	-	-												$ -	$ -	$ -
7			-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
9			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance	$ -

Total Distribution Revenues	$ -
Base Revenue Requirement	$ -
Difference	$ -
% Difference	

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 675	5.68%	$ 11,880	$ 4,068	$ 261	$ 592	$ 69	$ 650	$ 1,965	$ 46	$ 1,919	$ 75
1														

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), for the purpose of determining its rates revenue requirement. Table 1 below provides details regarding Hydro One Transmission's external revenues for the 2018-2027 period.

Table 1 - Transmission External Revenues ($M)

	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Secondary Land Use	25.6	27.7	29.1	46.5	28.8	28.0	24.3	24.6	24.9	25.1
Station Maintenance	4.6	4.0	3.5	3.4	3.4	3.4	3.4	3.4	3.2	3.2
Engineering & Construction	0.1	0.1	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other External Revenues	9.1	8.1	5.2	8.7	7.2	8.4	8.2	8.1	7.8	8.6
Total	**39.4**	**39.9**	**38.0**	**59.0**	**39.8**	**40.1**	**36.2**	**36.5**	**36.2**	**37.3**

External revenues earned through the provision of services to third parties are forecasted to be $40.1M in 2023. The 2023 external revenues are anticipated to decrease in 2024 and remain flat, below historical levels, through to 2027. Higher revenues in the 2021-2023 period are primarily attributable to Imperial Oil Limited's Waterdown to Finch Pipeline Project and the associated one-time easement transaction. Further details are provided in section 2.1 below.

As further described in Exhibit G-01-02, 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 focus on core work, while continuing to be responsive to external customer work requests where the utility has available resources and/or assets to accommodate the request. Costs associated with external work are described in Exhibit E-04-06. The costing of external work is determined on the basis of cost causality, consistent with the costing of internal work, using the standard labour rates, equipment rates, material surcharge, and overhead rates. An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit to transmission ratepayers. Further details relating to the costing of external work can be found in Exhibit 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

Secondary Land Use includes the Provincial Secondary Land Use Program (PSLUP). The PSLUP involves licensing and leasing Hydro One's transmission corridor lands to external parties for "secondary" land use purposes that are compatible with Hydro One Transmission's primary business operations. Typical uses include parking lots, municipal and private roadways, parks and trails, agricultural areas, water mains and other municipal infrastructure occupations, as well as public transit parking lots and station operations.

Hydro One Transmission manages the PSLUP on behalf of the Ontario Government, to whom Hydro One's transmission corridor lands were transferred under the *Reliable Energy and Consumer Protection Act, 2002*, S.O. 2002, c. 1 (the "Act"). Pursuant to the Act, (i) all expiring PSLUP agreements were transferred to the Province of Ontario as of December 31, 2002; (ii) remaining unexpired corridor agreements and associated revenue streams are retained by Hydro One until such time as these agreements expire; and (iii) upon expiration, the previously retained agreements and revenue streams by Hydro One are then also transferred to the Province of Ontario.

Subsequently, Hydro One and the Province of Ontario have had agreements that govern the parties' relationship in connection with the PSLUP. Hydro One provides front-line delivery services for the PSLUP on behalf of the Province of Ontario. Hydro One also manages all existing secondary land use agreements (including those previously transferred to the Province under the corridor land transfer arrangements). Hydro One retains PSLUP revenues for unexpired agreements until their expiry and employs a compensation model that involves the sharing of revenues between Hydro One and the Province of Ontario for new PSLUP agreements and for renewals of expired agreements which were previously transferred to the Province. The PSLUP revenue is generated by charging land rentals to external parties for new license and lease occupations and subsequent agreement renewals, as well as lump sum consideration for easements granted (e.g., water mains) and operational land sales completed (e.g., roadway).

Hydro One also manages a small portion of secondary land use revenue on its owned-properties that does not fall under the current PSLUP arrangements.

Table 2 below presents the PSLUP revenues for the 2018-2027 period.

Table 2 - PSLUP External Revenues ($M)

	Historical				**Bridge**	**Forecast**				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Secondary Land Use	25.6	27.7	29.1	46.5	28.8	28.0	24.3	24.6	24.9	25.1

The PSLUP revenues for 2023 Test Year are anticipated to be $28.0M which is lower compared to the prior five-year average (2018-2022: $31.5M) and slightly higher compared to the 2024-2027 forecast period. The variance is mainly attributed to the Waterdown to Finch Pipeline Project (the “Project”) undertaken by Imperial Oil Limited. The Project involves the replacement of approximately 63 km of an existing aging pipeline from Hamilton pump station to Toronto storage facility. A large section of the new pipe, approximately 43 km is located on provincial transmission corridor lands that are subject to the PSLUP. As a result of a one-time easement arrangement required for the Project, Hydro One estimates external revenue in the amount of approximately $36M during the 2020-2023 period. Hydro One has received or expects to receive $4M in 2020, $23M in 2021, and $9M in 2022 and 2023.

The forecasted amount in 2022 and 2023 represents a holdback and the payout is dependent on the timing of completion of final surveys and verifications of occupation. Currently, Hydro One anticipates to receive $5M in 2022 and the remaining $4M in 2023. Following the completion of the Project in 2023, the PSLUP revenues in the 2024-2027 period are anticipated to return to historical levels. As described in Exhibit G-01-02, Hydro One has an External Secondary Land Use Revenue Variance Account that tracks the difference between the actual PSLUP revenues and the revenues approved by the OEB. The variance account helps protect Hydro One's customers and keep them whole.

2.2 STATION SERVICES

Revenues from external work in the station services segment include specialized activities similar to those performed internally for Hydro One Transmission. These activities include repairing electrical equipment (such as transformers, breakers and switches), specialty machining (e.g. spindles and generator rotors), protective relay installation, maintenance and calibration, coordinating services to reconnect modified systems to the network, as well as providing meter services and emergency services. Customers seek out station services skills resident within Hydro One, requiring highly specialized staff able to perform work on a variety of high voltage equipment in a variety of work settings (such as nuclear and fossil fuel environments). Work is performed in accordance with commercially negotiated contracts which reflect market level pricing.

Hydro One provides support to the external market place in areas which are related to Hydro One Transmission. This work is primarily tied to support Ontario's key generation suppliers: Bruce Power LP, Ontario Power Generation Inc. and Siemens Westinghouse Inc. in support of Ontario Power Generation Inc.

Table 3 below presents the Station Maintenance revenues for the 2018-2027 period.

Table 3 - Station Maintenance External Revenues ($M)

	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Station Maintenance	4.6	4.0	3.5	3.4	3.4	3.4	3.4	3.4	3.2	3.2

The Station Maintenance revenues for 2023 Test Year are anticipated to be $3.4M which is slightly lower compared to the prior five-year average (2018-2022: $3.8M) and in line with the 2024-2027 forecast period. The variance is mainly due to station maintenance services scope adjustments as Hydro One continues to focus on its internal work program requirements.

2.3 ENGINEERING AND CONSTRUCTION

Hydro One's engineering and construction activities focus on various work supporting Hydro One Telecom Inc. (HOT) business segment. In particular, Hydro One supports HOT with its customers request for new interconnections with Hydro One's optical fibre infrastructure by providing design/quotes/builds related to HOT work within Hydro One's transmission station property.

Table 4 below presents the Engineering and Construction external revenues for the 2018-2027 period.

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

	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Engineering & Construction	0.1	0.1	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4

The Engineering and Construction revenues in 2023 Test Year are anticipated to be $0.4M which is higher compared to the prior five-year average (2018-2022: $0.2M) and in line with the 2024-

2027 forecast period. The variance is mainly due to an increased number of requests from HOT for new interconnections within Hydro One's optical fibre infrastructure.

2.4 OTHER

The Other category of external revenues include 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), revenues from special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous external revenues. These include transfer price charges to Hydro One's affiliate companies.

Table 5 below presents the Other category of external revenues for the 2018-2027 period.

Table 5 - Other External Revenues ($M)

	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Other External Revenues	9.1	8.1	5.2	8.7	7.2	8.4	8.2	8.1	7.8	8.6

The Other category of external revenues is forecasted to be $8.4M in 2023 Test Year which is higher than the prior five-year average (2018-2022: $7.7M) and in line with the 2024-2027 forecast period average ($8.2M).

Appendix 2-H
Transmission External Revenue

USoA #	USoA Description	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	Bridge Year	Test Year
		2018	2019	2020	2021	2022	2023
	Reporting Basis						
4325	**Tx External Revenue**	$ 39	$ 40	$ 38	$ 59	$ 40	$ 40
Total		$ 39	$ 40	$ 38	$ 59	$ 40	$ 40

Description	**Account(s)**
Transmission External Revenue	4325

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

Account 4325 -Tx External Revenue

	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis						
Secondary Land Use	$ 26	$ 28	$ 29	$ 47	$ 29	$ 28
Station Maintenance	$ 5	$ 4	$ 4	$ 3	$ 3	$ 3
Engineering & Construction	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Other External Revenues	$ 9	$ 8	$ 5	$ 9	$ 7	$ 8
Total	$ 39	$ 40	$ 38	$ 59	$ 40	$ 40

DISTRIBUTION EXTERNAL REVENUES

1.0 INTRODUCTION

This exhibit details Hydro One Distribution's external revenues which are deducted from the revenue requirement in the derivation of rates revenue requirement. External revenues are earned through the provision of services to third parties and through joint use of Hydro One Distribution assets by third parties. These revenues offset Hydro One's Distribution revenue requirement, reducing the required revenue to be collected from ratepayers.

External revenues are categorized as regulated and unregulated. Regulated revenues are based on OEB-approved specific service charges, which are detailed in Exhibit L-04-01, whereas unregulated revenues are based on charges determined by Hydro One.

Revenue received through the Standard Supply Service Charge is also reflected in this schedule. 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 in the derivation of rates revenue requirement.

Table 1 below provides a breakdown of witness accountability for categories of external revenue.

Table 1 - External Revenue Accountabilities

External Revenue	Witness
Regulated - Retail Service Revenues	Spencer Gill
Regulated - Joint Use	Bruno Jesus
Regulated - Sentinel Lights	Spencer Gill
Regulated - Other External Work	Bruno Jesus
Regulated - Distributor Generator Studies	Bruno Jesus
Unregulated - Joint Use	Bruno Jesus
Unregulated - Other External Work	Chong Kiat Ng
Unregulated - Storm Revenue	Chong Kiat Ng

A summary of the company's historical (2018-2021), bridge (2022), and forecasting period (2023-2027) Distribution external revenues is shown in Table 2 below.

Table 2 - Distribution External Revenues ($M)

Revenue	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Forecast	Forecast	Forecasting Period				
Regulated Revenue	36.1	35.9	25.9	34.5	35.7	37.4	37.5	37.4	36.9	36.9
Unregulated Revenue	10.0	5.7	3.4	3.6	3.8	3.8	3.8	3.8	3.8	3.8
Sub-Total External Revenue	**46.1**	**41.6**	**29.3**	**38.1**	**39.5**	**41.2**	**41.3**	**41.2**	**40.7**	**40.7**
Standard Supply Service Charge	3.8	3.8	3.8	4.2	4.2	4.2	4.3	4.3	4.3	4.4
MicroFIT Revenue	-	-	-	0.8	0.8	0.8	0.8	0.8	0.8	0.8
ST Local Transformation Charge	-	-	-	-	-	0.2	0.2	0.2	0.2	0.2
Total External Revenue and Other	**49.9**	**45.4**	**33.1**	**43.1**	**44.5**	**46.4**	**46.6**	**46.5**	**46.0**	**46.1**

The cost of external work is determined on the basis of cost causality with estimates calculated in the same way for internal work, using the standard labour rates, equipment rates, material surcharge, and overhead rates. For details on the costing of work, please refer to Exhibit C-09-01.

The Microfit Revenue and ST Local Transformation Charge revenue line items shown in Table 2 above represent additions since the previous filing. The descriptions of each are detailed below.

Microfit Revenue: The current OEB approved province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator Service Classification is $4.55 per month. As per the Filing Requirements[1], any revenue related to microFIT charges must be recorded as a revenue off-set in USofA Account 4235 – Miscellaneous Service Revenue and not be included as part of the base distribution revenue requirement.

Sub-Transmission (ST) Local Transformation Charge: In this Application, Hydro One proposes to offer a new local transformation option for its Sub-Transmission (ST) customers, effective January 1, 2023. ST customers who choose to use Hydro One-owned local transformers will be subject to a fixed “local transformation charge” of $200 per month. The revenue from this monthly local transformation charge will be recorded as a revenue off-set in USofA Account 4220 – “Other Electric Revenue” and not be included as part of the base distribution revenue requirement. The ST local transformation charge is further discussed in Exhibit L-01-01.

Costs associated with the recognition of these external revenues, are presented in exhibits E-04-07. OEB-approved specific service charges are discussed in Exhibit L-04-01.

For unregulated work, Hydro One adds an appropriate margin above its cost to cover, at a minimum, the risk of non-payment by third parties.

[1]Filing Requirements Chapter 2, section 2.3.3

2.0 DESCRIPTION OF DISTRIBUTION EXTERNAL REVENUES

This section describes each External Revenue component and discusses relevant trends for each.

2.1 REGULATED EXTERNAL REVENUE

Regulated external revenues for the 2023-2027 forecasting period are set out in Table 3 below. The sources of these revenues and relevant variances in each are discussed below.

Table 3 - Regulated Revenues ($M)

	Historical				Bridge	Test	Forecasting Period			
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Retail Service Revenues	15.3	14.7	5.0	14.0	15.0	15.1	15.1	15.1	14.5	14.6
Joint Use	13.0	14.4	14.9	14.8	15.1	15.7	15.8	15.8	15.9	15.9
Sentinel Lights	3.0	3.0	3.0	2.8	2.7	2.6	2.5	2.4	2.3	2.2
Other External Work	2.0	3.0	2.7	2.4	2.4	3.5	3.6	3.6	3.7	3.7
Distributor Generator Studies	2.8	0.8	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	**36.1**	**35.9**	**25.9**	**34.5**	**35.7**	**37.4**	**37.5**	**37.4**	**36.9**	**36.9**

2.1.1 RETAIL SERVICE REVENUES

Table 4 - Retail Service Regulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Retail Service revenues	15.3	14.7	5.0	14.0	15.0	15.1	15.1	15.1	14.5	14.6

As described in Exhibit L-04-01, Hydro One provides a range of customer administration services. Late payment charges, which are the primary driver of retail service revenues, were substantially lower in 2020 due to Hydro One suspending these charges in response to the COVID-19 pandemic. Bridge and test year forecasts reflect a return to typical late payment charges and an expected increase over the forecasting period as the customer base increases. Collections activities were similarly discontinued in response to the pandemic, resulting in lower revenues in 2020. 2021 reflects a partial recovery to normal collection activities, and 2022 onward reflect a return to normal collection activities as well as the expectation that revenues will increase as the customer base increases. Charges from new account set up requests completed via the call center are expected to decline in bridge and test years as more customers move to online self-service tools.

2.1.2 JOINT USE

Table 5 - Joint Use Regulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Joint Use	13.0	14.4	14.9	14.8	15.1	15.7	15.8	15.8	15.9	15.9

Joint use revenues are generated from third parties who place attachments on Hydro One Distribution's poles. For this right, Hydro One charges an attachment fee per pole. As of 2021, there are approximately 560 agreements in place with joint use partners, such as reciprocal and non-reciprocal telecommunications companies, local distribution companies (LDCs), generators, and municipalities. About 90% of the joint use revenue comes from telecommunications companies.

Hydro One's current forecast Joint Use revenues reflects relatively stable work volumes by the company's Joint Use Partners, with a moderate increase in 2023 reflecting the integration of regulated joint use revenues from the Acquired Utilities, as discussed in Exhibit A-08-01.

2.1.3 SENTINEL LIGHT REVENUES

Table 6 - Sentinel Light Regulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Sentinel Lights	3.0	3.0	3.0	2.8	2.7	2.6	2.5	2.4	2.3	2.2

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 limited to customers already participating in the rental program.

2.1.4 OTHER EXTERNAL WORK

Table 7 - Other External Work Regulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Other External Work	2.0	3.0	2.7	2.4	2.4	3.5	3.6	3.6	3.7	3.7

Other external work is primarily work performed by Hydro One on behalf of Bell Canada as a part of new 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 Hydro One 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”).

Other external work also includes work performed by Hydro One on assets owned by its joint use partners, as well as an allocation of corporate functions and service charges from Hydro One that is charged to Hydro One Telecom Inc. (Telecom) and Hydro One Remotes Communities Inc. (Remotes), and replacing streetlights for the Township of Ignace in accordance with Hydro One’s Streetlight Maintenance Agreement.

Regulated external revenues received from Hydro One affiliates include $0.3M forecasted for work related to Remotes and $0.4M related to Telecom. 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.

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 8 - Distributor Generator Studies Work Regulated Revenues ($M)

	Historical				Bridge	Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Distributor Generator Studies	2.8	0.8	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Hydro One recognizes revenues for undertaking Connection Impact Assessments (CIAs) in response to connection requests from generation proponents in the Ontario.[2] Hydro One performs CIAs based on a customer request that includes the proposed size of the generator and where it will be located. The associated revenues are presented in Table 8.

In 2018, Hydro One received a large number of CIA applications for connections less than or equal to 500 kilowatts under the Feed-in Tariff (FIT) program, largely due to the anticipated cancellation of the program. The volume of such applications has since declined and is expected to be low during the 2023-2027 forecasting period, as currently there is no active IESO contract program.

Distributed Energy Resources activity in Ontario has shifted from retail generators participating in historical IESO procurement programs to behind-the-meter (BTM) load displacement

[2] 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.

generators participating in the Ontario Net Metering program and the IESO's Industrial Conservation Initiative (ICI) program. Hydro One saw a gradual increase in net metering projects from 2018 to 2020, corresponding with the end of FIT program. The company received a large volume of CIA applications under the net metering program in 2020, and expects a slight decrease in these applications after 2021, with proponents of such projects having reached a saturation point. The ICI program allows large distribution connected load customers to reduce their Global Adjustment cost by reducing their peak during the five Ontario peaks. The CIA applications received under ICI program are all categorized as Capacity Allocation Required (CAR) projects, as their requested capacity is always greater than 500 kW. The number of CIA applications for CAR projects is expected to remain consistent during the 2023-2027 forecasting period.

2.2 EXTERNAL UNREGULATED REVENUES

Historical and forecast unregulated external revenues are set out in Table 9 below.

Table 9 - Unregulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Joint Use	0.4	0.6	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other External Work	3.3	4.1	2.9	3.6	3.8	3.8	3.8	3.8	3.8	3.8
Storm Revenue	6.3	1.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**10.0**	**5.7**	**3.4**	**3.6**	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**

2.2.1 JOINT USE REVENUE - UNREGULATED

Table 10 - Joint Use Unregulated Revenues ($M)

	Historical			Bridge		Forecasting Period[3]				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Joint Use	0.4	0.6	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[3] Forecast values of $43,446 annually over the forecasting period, but due to the table being shown in millions, the values show as $0.0.

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 costs of maintenance, therefore, an annual fee is charged to recover these maintenance costs. Unregulated Joint Use revenue is anticipated to remain constant throughout the forecasting period based on previous volumes at $42,336.00. There was a reduction to this program because Hydro One Forestry Services no longer engage in vegetation management for Telecom owned poles.

2.2.2 OTHER EXTERNAL WORK - UNREGULATED

Table 11 - Other Work Unregulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Other External Work	3.3	4.1	2.9	3.6	3.8	3.8	3.8	3.8	3.8	3.8

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

External training covers a wide range of practical and classroom delivered courses. Packaged delivery of numerous trade and professional technical courses are delivered for Lines, Power Substation Electricians, Metering Technicians, and Electrical Operators. Customers include utilities and contractors from Ontario with training delivered to a cross-section of employees from various trades or 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.

2.2.3 STORM REVENUE - UNREGULATED

Table 12 - Storm Unregulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Storm Revenue	6.3	1.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Storm revenues are related to events outside the Province of Ontario that Hydro One has provided mutual assistance to by deploying resources to help other utilities affected by major power outages. These instances are unpredictable and dependent on Hydro One's ability to deploy storm relief outside jurisdictions and, accordingly, are not forecast.

The following attachment(s) are provided as part of this section:

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

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year	Bridge Year	Bridge Year	Bridge Year	Bridge Year
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Reporting Basis										
4225/4325	Retail Services Revenues - Regulated	15.3	14.7	5.0	14.0	15.0	15.1	15.1	15.1	14.5	14.6
4325	Joint Use - Regulated	13.0	14.4	14.9	14.8	15.1	15.7	15.8	15.8	15.9	15.9
4325	Sentinel Lights - Regulated	3.0	3.0	3.0	2.8	2.7	2.6	2.5	2.4	2.3	2.2
4325	Other External Work - Regulated	2.0	3.0	2.7	2.4	2.4	3.5	3.6	3.6	3.7	3.7
4325	Distributor Generator Studies - Regulated	2.8	0.8	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sub-total Regulated Revenues		36.1	35.9	25.9	34.5	35.7	37.4	37.5	37.4	36.9	36.9
4325	Joint Use - Unregulated	0.4	0.6	0.4	-	-	-	-	-	-	-
4325	Other External Work - Unregulated	3.3	4.1	2.9	3.6	3.8	3.8	3.8	3.8	3.8	3.8
4325	Storm Revenue - Unregulated Work	6.3	1.0	0.1	-	-	-	-	-	-	-
Sub-total Unregulatd Revenues		10.0	5.7	3.4	3.6	3.8	3.8	3.8	3.8	3.8	3.8
4086	Standard Supply Service Charge	3.8	3.8	3.8	4.2	4.2	4.2	4.3	4.3	4.3	4.4
4235	MicroFIT Revenues	-	-	-	0.8	0.8	0.8	0.8	0.8	0.8	0.8
4220	ST Local Transformation Charge	-	-	-	-	-	0.2	0.2	0.2	0.2	0.2
Other Operating Revenues											
Other Income or Deductions											
Total		**$ 49.9**	**$ 45.4**	**$ 33.1**	**$ 43.1**	**$ 44 5**	**$ 46.4**	**$ 46.6**	**$ 46.5**	**$ 46.0**	**$ 46.1**

CGAAP
Enter Transition Year
CGAAP
$ -

Description / **Account(s)**

Specific Service Charges: 4235

Late Payment Charges: 4225

Other Distribution Revenues: 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4230, 4240, 4245

Other Income and Expenses: 4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4357, 4360, 4362, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4410, 4415, 4420

Note: Add all applicable accounts listed above to the table and include all relevant information.

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 re-issued, approved and executed annually by senior executives with the relevant accountability from each affiliate that is a party to the agreement.

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

Affiliate Services other than the shared 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 applied as an offset to Hydro One Networks' Transmission and

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

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-05-01.

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, which are expected to be in place for the 2022 bridge year and the 2023 test year, as well as subsequent years. As noted, some of the Affiliate Services provided by Hydro One Networks to its affiliates are shared 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 Affiliate Services Provided by Hydro One Networks Inc.

AFFILIATE SERVICE PROVIDER	AFFILIATE SERVICE RECIPIENT(S)	AFFILIATE SERVICES
Hydro One Networks Inc.	Hydro One Limited Hydro One Inc. Hydro One Remote Communities Inc. (Remotes) Hydro One Telecom Inc. (Telecom) B2M LP Niagara Reinforcement LP Hydro One Sault Ste. Marie LP (HOSSM)	***a) General Counsel Services*** – Professional legal advice and input and regulatory services. ***b) 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. ***c) Corporate Services*** – Facility management and real estate services, outsourcing services, human resource services, labour relations, corporate communications and security, Indigenous relations, information management services, computer equipment leases and system services. ***d) Telecommunications Services*** – Various telecommunications-related services, including field and engineering, logistics, corporate, construction, telecommunication and information technology services. ***e) Other Services*** – Customer services operation and information management. ***f) System Services (for Remotes and Telecom Only)*** – Use of Common computer infrastructure and software such as SAP. ***g) 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. ***h) 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, work methods and training services, metering/technician services, lines services, safety services, fleet services, environmental services, engineering services, flight services, distribution planning and technical services, joint use services, and health and safety 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.	Hydro One Telecom 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	***Master Agreement*** – Engineering services, environmental services, facilities, fleet services, flight safety services, forestry services, health and safety services, joint use services, safety services, settlement services, supply chain, transmission, construction and maintenance services.
Hydro One Networks Inc.	Hydro One Sault Ste. Marie LP	***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 Niagara Reinforcement LP	***a) Lines and Forestry Services*** – Line patrols and maintenance, and vegetation management services. ***b) Management Services*** – Services to assist with the performance of B2M GP Inc.'s management activities.
Hydro One Networks Inc.	Hydro One Telecom Inc.	***Microwave Tower Lease Agreement*** – Leasing available towers (no longer being used by Hydro One Networks Inc.) to Hydro One Telecom Inc.; (b) leasing space to Hydro One Telecom Inc. on certain microwave towers still being used by HONI (space only towers); and (c) allowing Hydro One Telecom 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.	Hydro One Telecom Inc.	***Dark Fibre IRU Agreement*** – Grant by Hydro One Networks Inc. to Hydro one Telecom 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.	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 Hydro One Telecom 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, which are expected to be in place for the 2022 bridge year and the 2023 test year, as well as subsequent years. As noted, some of the Affiliate Services received by Hydro One Networks from its affiliates are shared 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 SERVICES RECEIVED BY HYDRO ONE NETWORKS

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

AFFILIATE SERVICE PROVIDER	AFFILIATE SERVICE RECIPIENT(S)	AFFILIATE SERVICES
Hydro One Limited	Hydro One Inc. Hydro One Networks Inc. Hydro One Telecom Inc.	***a) Chief Legal Officer services*** – Professional legal advice and services. ***b) President and CEO services*** – Strategic direction and management, strategic approval with respect to investment decisions, review of policies and procedures, treasury operations and tax planning, financial control and reporting. ***c) Chief Financial Officer services*** – Strategic direction and management in an attempt to ensure that the Services Recipient's corporate goals are achieved.

Hydro One Inc.	Hydro One Limited Hydro One Networks Inc. Hydro One Remote Communities Inc. Hydro One Telecom Inc. Hydro One Sault Ste. Marie LP B2M LP Niagara Reinforcement LP	***a)*** ***Administrative, Corporate Secretary and Code of Conduct services*** – Administrative, corporate secretary as well as guidance on business ethics and support in the form of a business code of conduct. ***b)*** ***Financial Services*** – Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting. ***c)*** ***Ombudsman Services*** – Facilitate the resolution of customer complaints that remain unresolved after having been processed through Hydro One's complaints handling process.

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
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, and training.

5.0 KEY TERMS OF AFFILIATE SLAs

Hydro One Networks' approach to Affiliate Services is 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 re-issued, approved and executed annually by senior executives with the relevant accountability from each affiliate that is a party to the agreement.

5.1 PRICING AND COST ALLOCATION MECHANISMS

Where Hydro One Networks provides Affiliate 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 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) for such 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 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 agreements contain appropriate confidentiality provisions that generally restrict access to confidential information and/or require each party to protect the confidentiality of the other party's non-public, sensitive information, such as 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 agreements also allocate risks, including through reciprocal indemnification clauses wherein each party agrees to indemnify the other against damages attributable to the indemnifying party's wrongful actions. These clauses contain common exclusions of liability for certain categories of damages. As well, there are provisions that allocate risks related to deficiencies in the services provided and for the incurrence of material incremental costs in providing services.

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 Services thereunder, which cannot be resolved by the applicable directors or managers, a dispute resolution mechanism is included in the agreements providing that any such dispute can be escalated to the President of the ultimate parent of the Hydro One entities (i.e. Hydro One Limited).

This page left blank intentionally.

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 and Distribution load forecasts. The load forecasts in support of this Application were prepared in February 2021, using the economic and forecast information then available.

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, and Exhibit L in respect of Distribution.

2.0 KEY ASSUMPTIONS FOR THE DISTRIBUTION AND TRANSMISSION LOAD FORECASTS

Key information used as inputs in developing the load forecasts are Ontario GDP by sector, provincial demographics, industrial production and commercial floor space forecasts by segment, as well as energy prices.[2] The forecasts for these inputs are based on the most recent information available at the time the load forecasts were developed in February 2021. 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

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

[2] These are sourced from the Canada Energy Regulator (CER) except for coal as coal prices are not available from the CER and is therefore sourced from IHS Global Insights.

Appendices A to C of Exhibits D-04-01 and in Exhibit 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 three years, the manufacturing sector continued to experience slow growth along with the world economy. This growth was not experienced broadly. Demand for Paper, Printing, Petroleum and Coal, Primary Metals, Transportation Equipment, and Furniture experienced an overall decline during the past three years. Ontario GDP grew by 2.8 percent in 2017, 2.8 percent in 2018, 2.1 percent in 2019, and is expected to decline by 5.8 percent in 2020 due to COVID-related closures.[3] Based on the consensus forecast, which is an average of the forecasts produced by major banks and forecasting houses as defined in Appendix A, Ontario GDP is expected to grow by 4.5 percent in 2021, 4.2 percent in 2022, and by an average of 2.0 percent per year over the years 2023 to 2027. All forecasts presented in this Exhibit are based on information available as of February 2021 so that the forecasts account for the continuation of the pandemic in the short run and assume positive economic impacts over the long term resulting from a successful vaccination program. Appendix A provides the details of the consensus forecast for Ontario GDP along with the sources of the forecast. The source for all other economic/demographic variables is provided in Appendix 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 attachment D-03-01-01.

2.2 PROVINCIAL POPULATION FORECAST

The Ontario population grew 1.4 percent in 2017, 1.7 percent in 2018 and 1.6 percent in 2019, and is expected to grow by 1.3 percent in 2020. The forecast indicates that the Ontario population is expected to grow at 1.3 percent in 2021 and 2022 and by an average rate of 1.0 percent over the years 2023 to 2027 in line with its long-term historical average. Population growth contributes positively to the load forecast.

[3] All 2020 data points will not be available on a final basis until the end of 2021.

2.3 PROVINCIAL HOUSING FORECAST

Helped by population growth and relatively low but rising interest rates, housing demand in Ontario continued to grow at a moderate pace over the last four years. Housing starts statistics showed 79,900 new houses in 2017, 79,100 in 2018, 69,000 in 2019, and is expected to be 77,600 in 2020. The consensus forecast calls for 75,200 housing starts in 2021, 76,500 in 2022, and an average of 73,700 per year between the years 2023 and 2027. Appendix A provides the details of the consensus forecast for Ontario housing starts.

2.4 COMMERCIAL FLOOR SPACE FORECAST

Due to continued economic growth and relatively low but rising interest rates, the pace of commercial construction activities was moderate over the recent years. Commercial floor space grew by 0.2 percent in 2017, 0.8 percent in 2018, and 0.7 percent in 2019 and is expected to have grown by 0.4 percent in 2020. The forecast calls for 0.6 percent growth in 2021 and 2022 and average of 0.7 percent per year between 2023 and 2027. 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 three years, the manufacturing sector continued its slow growth but the growth was not broad-based. As previously discussed, Demand for Paper, Printing, Petroleum and Coal, Primary Metals, Transportation Equipment, and Furniture experienced an overall decline during the past three year. Industrial GDP grew by 0.2 percent in 2017, 3.0 percent in 2018, and then declined by 0.8 percent in 2019, and is expected to have declined by 9.6 percent in 2020 due to COVID-related closures. The forecast calls for growth of 10.8 percent in 2021, 5.6 percent in 2022, and an average annual growth rate of 1.5 percent between 2023 and 2027. 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

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

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Global Insight (Nov 2020)	1.7	-5.7	3.8	3.5	2.0	2.2	2.2	1.9	1.7
Conference Board (Nov 2020)	1.9	-5.8	5.3	5.0	1.7	1.4	2.0		
U of T (Jan 2020)	2.1	-5.8	3.9	4.8	3.2	2.5	2.3	2.2	2.2
C4SE (Aug 2020)	1.7	-5.9	4.2	3.1	2.1	1.9	1.9	1.9	1.7
CIBC (Jan 2021)	2.1	-5.5	3.9	5.2					
BMO (Oct 2020)	1.9	-5.6	6.0						
RBC (Dec 2020)	2.1	-5.6	5.5	5.0					
Scotia (Dec 2020)	1.6	-5.7	4.2	3.2					
TD (Dec 2020)	1.6	-6.2	5.6	4.1					
Desjardins (Jan 2021)	2.1	-6.0	3.7	5.1					
Central 1 (Oct 2020)	1.7	-6.0	4.4	2.7	1.8				
National Bank (Jan 2021)	2.1	-5.5	3.6	4.2					
Laurentian Bank (Jan 2021)	2.1	-5.8	4.2	4.5					
Average	**1.9**	**-5.8**	**4.5**	**4.2**	**2.2**	**2.0**	**2.1**	**2.0**	**1.9**

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

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Global Insight (Nov 2020)	69.0	80.7	71.7	72.5	71.0	64.7	58.4	56.4	56.4
Conference Board (Nov 2020)	69.0	83.1	88.6	91.1	91.0	90.7	90.2		
U of T (Jan 2020)	69.0	81.3	70.7	71.3	71.8	72.5	73.2	73.8	74.4
C4SE (Aug 2020)	69.0	71.7	71.6	76.4	77.8	79.6	79.4	79.4	77.9
CIBC (Apr 2020)	69.0	43.0	68.0						
BMO (Oct 2020)	69.0	81.0	76.0						
RBC (Dec 2020)	69.0	83.2	77.5	75.0					
Scotia (Dec 2020)	69.0	78.0	63.0	66.0					
TD (Dec 2020)	70.1	81.1	82.2	81.3					
Desjardins (Jan 2021)	69.0	81.3	85.2	78.2					
Central 1 (Oct 2020)	69.0	80.8	73.3	74.4	73.2				
National Bank (Jan 2021)	69.0	82.5	77.5	75.8					
Laurentian Bank (Jan 2021)	69.0	81.4	73.0	79.5					
Average	**69.1**	**77.6**	**75.2**	**76.5**	**77.0**	**76.9**	**75.3**	**69.9**	**69.6**

Forecast updated on Feb 3, 2021

DATA FOR HYDRO ONE LOAD FORECAST

This exhibit has been filed separately in MS Excel format.

TRANSMISSION LOAD FORECAST AND METHODOLOGY

1.0 INTRODUCTION

This Exhibit discusses the Hydro One Transmission system load forecast and the related methodology. The key load forecast supporting Hydro One's transmission rate case 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 February 2021 using the available economic and forecast information.

Hydro One Transmission's forecast of the average 12-month peak load for 2023 to 2027 for Ontario as a whole and for the three transmission rate categories are shown in Table 1. The impacts of Conservation and Demand Management (CDM) and embedded generation are included. Hydro One worked with the Independent Electricity System Operator (IESO) and used their latest CDM assumptions in preparing the load forecast in this rate application, as detailed in Section 3.1 below.

Table 1: Hydro One's 2023-2027 Load Forecast (12-Month Average Peak in MW)

	Ontario Demand	Hydro One Rate Categories (Charge Determinants)		
		Network	Line Connection	Transformation Connection
2023	19,451	19,252	18,689	15,898
2024	19,527	19,327	18,761	15,959
2025	19,547	19,347	18,780	15,975
2026	19,584	19,384	18,816	16,006
2027	19,607	19,406	18,837	16,024

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

Hydro One uses a number of methods, such as econometric models, end-use models, customer forecast surveys and hourly load shape analyses to produce the forecasts required for its transmission business. 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-2016-0160, and EB-2019-0082) taking into account the implications of latest available information (e.g., statistical significance of variables used). All forecasts presented in this Exhibit are weather-normalized, meaning that abnormal weather effects are removed from the base year 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 add 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 improvement 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 establishments in the country, such as all major banks, IHS Global Insight, the Conference Board of Canada, the Centre for Spatial Economics and the University of Toronto. 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 Section 7.1 of the SPF provided at Exhibit B-01-01.

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 2021 to 2027. 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.

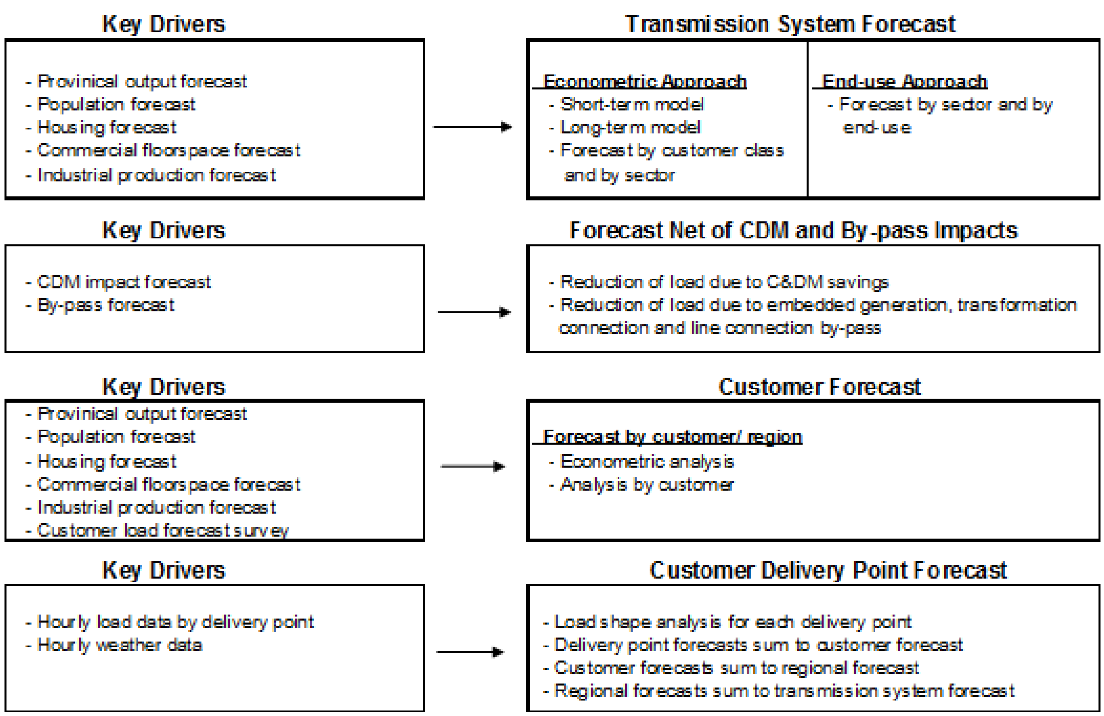


Figure 1: Key Assumptions Used in the Forecast

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's system energy demands. The load forecast also takes into account historical actual load and trends up to the end 2020. The economic and demographic forecasts used to develop transmission load forecast are discussed in Exhibit D-03-01. The actual load is presented in Attachment D-04-01-01.

3.1 CONSERVATION AND DEMAND MANAGEMENT FORECAST

In EB-2010-0002, the OEB directed Hydro One to "work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA." In EB-2012-0031, Hydro One worked with stakeholders and the OPA to satisfy this directive, and the methodology set out in the report "Incorporating CDM Impacts in the Load Forecast" was accepted by the OEB.[1]

In October 2017, the Ministry of Energy released an update to the 2013 Long-Term Energy Plan (2013 LTEP), which did not provide updated figures for peak CDM relating to conservation programs that were included in the 2013 LTEP.[2] Hydro One has used the 2013 LTEP assumptions and taken into account the IESO's latest province-wide conservation forecast to establish the CDM impacts in the load forecast. Hydro One adopted two CDM categories that are consistent with the IESO's (then the OPA) 2013 LTEP information: energy efficiency programs and codes and standards. Details of the latest information that was provided in February 2021 by the IESO, which are consistent with the IESO's latest Annual Planning Outlook (APO), and the methodology used by Hydro One to derive the CDM impacts for the three charge determinants, have been documented in sections 3.1 and 4.0 of this exhibit.

---

[1] EB-2012-0031, Exhibit A-15-02-01

[2] The detailed breakdown of assumptions underpinning the 2013 LTEP was released by the OPA in February 2014.

Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2027. These CDM peak impacts are consistent with the 2013 LTEP and the latest figures from the IESO's APO.

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	206
2007	778	554
2008	893	636
2009	997	710
2010	1,167	830
2011	1,318	957
2012	1,470	1,091
2013	1,621	1,206
2014	1,820	1,343
2015	1,942	1,416
2016	2,167	1,646
2017	2,099	1,568
2018	2,391	1,830
2019	2,511	1,931
2020	2,493	1,952
2021	2,544	2,027
2022	2,609	2,128
2023	2,683	2,224
2024	2,667	2,237
2025	2,691	2,283
2026	2,725	2,334
2027	2,802	2,433

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

3.2 EMBEDDED GENERATION FORECAST

In relation to Ontario demand, a total of 586 MW of embedded generation was assumed to be in place in 2017, with an additional 20 MW in 2018, 8 MW in 2019, 21 MW in 2020, 36 MW in 2021, and 2 MW in 2022. No new embedded generation is assumed in the load forecast after 2022. The figures represent 12-month average peak and are based on information provided by IESO, which reflects renewable energy projects in this regard.

4.0 LOAD FORECASTING METHODOLOGY

Hydro One Transmission's system load forecast is developed using both econometric and end-use approaches. The forecast base year is corrected for abnormal weather conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized base year value. The load impacts of CDM and embedded generation are added back to the historical values during the modeling process (see Figure 2 and Section 4.3).

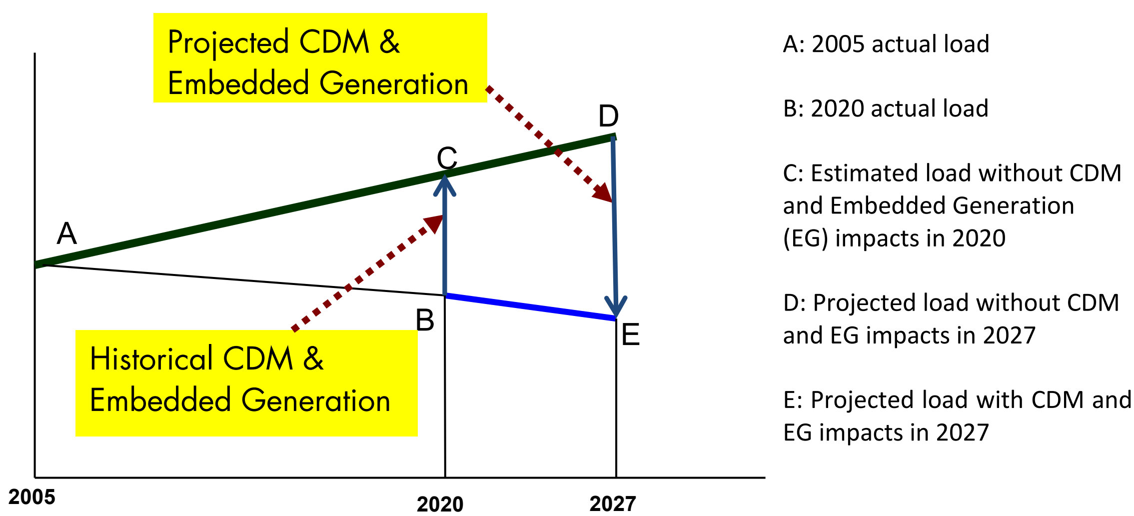


Figure 2: Incorporation of CDM and Embedded Generation in the Load Forecast

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 growth. 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 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 in the past 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-2016-0160, and EB-2019-0082). Normal weather data is based on the average weather conditions experienced over the last 31 years. This methodology is also used by the IESO. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year.

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 cover 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 weekly, monthly or 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.

4.2.1 WEATHER CORRECTION PRACTICES IN OTHER JURISDICTIONS

Hydro One completed a study in 2008 on weather normalization practices by surveying over 50 utilities in North America. The study was submitted to the OEB for review in the transmission rate case EB-2008-0272. The major findings of the study are summarized below.

- Most utilities use long-term weather data to calculate the weather normal conditions.
- The most commonly used period for weather normalization is at least 30 years; no utilities use less than 10 years of weather data to do weather normalization.
- Weather normalization surveys undertaken by Edison Electric Institute, BC Hydro and ITRON show similar results as Hydro One's survey.
- Most utilities update their weather data set and weather normalization analysis on an annual basis.

- Very few utilities have changed their weather normalization practices in response to global warming or other reasons.
- The survey results were supportive of Hydro One’s weather-normalization methodology, which is based on the use of 31 years of weather data to define normal weather conditions.

The above study confirms that the weather normalization methodology used by Hydro One is appropriate.

For the purposes of settlement only, in Hydro One’s 2014 transmission rate submission (EB-2014-0140), Hydro One agreed to use the mid-point between its conventional weather-normal forecast and an alternative forecast based on a 20-year, upward-sloping temperature trend (i.e. maximum and minimum temperatures are getting warmer). However, as shown in Figures 3 and 4, the “trend” has not been upward-sloping in recent years. For example, the maximum temperature, after achieving a peak in 2011, is in a downward trend. The Figures present the maximum and minimum daily temperatures between 1953 and 2020.

Figure 3. Toronto Pearson International Airport: Maximum of Average Daily Temperature

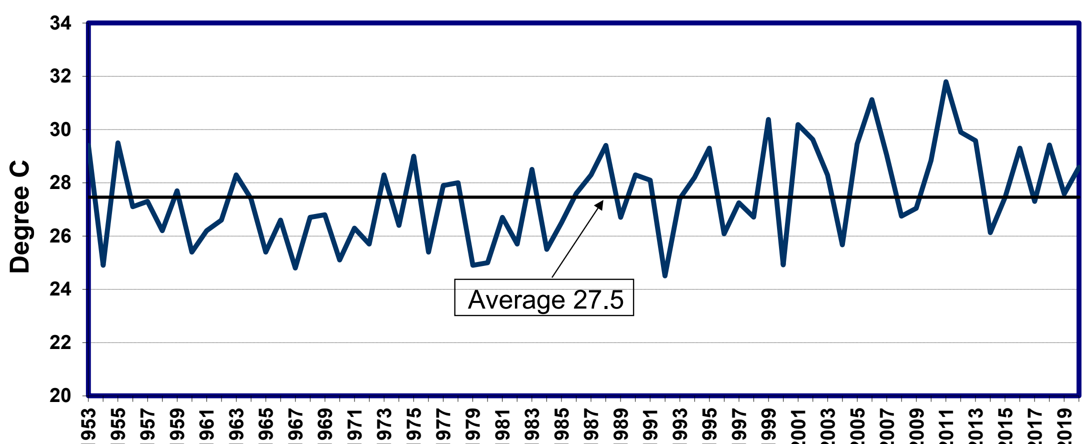
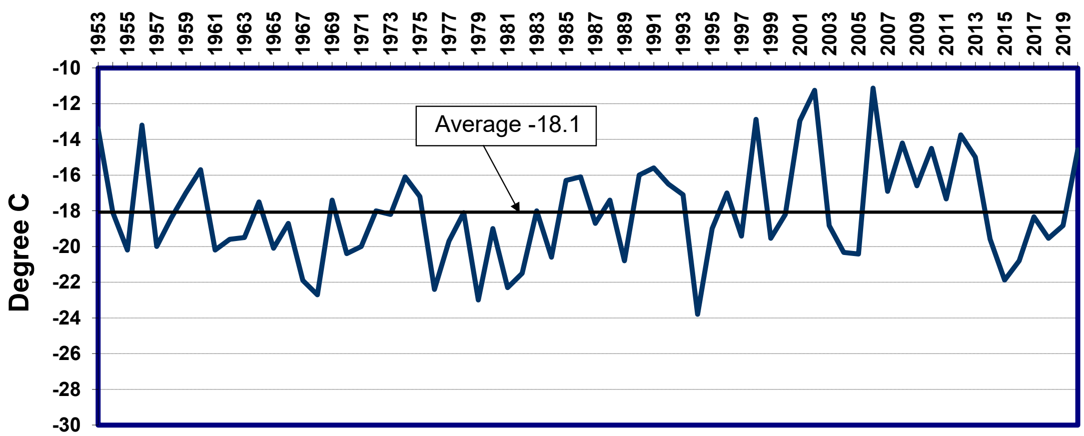


Figure 4: Toronto Pearson International Airport:
Minimum of Average Daily Temperature



4.3 HYDRO ONE FORECASTING METHODOLOGY

Hydro One uses econometric (top-down) and end-use (bottom-up) models to forecast the transmission system load. For the top-down approach, both monthly and annual econometric models are used. For the bottom-up approach, end-use models are used to analyse the transmission system load by sector (i.e. residential, commercial, and industrial customers). Key information used in the analysis includes economic data, demographics, industrial production and commercial floor space forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. This forecasting methodology was reviewed and approved by the OEB in previous Hydro One's transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2016-0160, and EB-2019-0082).

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 MODEL

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. Moreover, 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, except for the price of coal which is not available from the CER. The Global Insight forecast for the price of coal is used instead.

Comparing use of Single versus Multiple Weather Stations

In the OEB Decision in EB-2017-0049, Hydro one was directed to carry out further investigation on the use of weather data from multiple locations in the province. In response to the OEB direction, Hydro One compared two sets of regression results for annual econometric models using different weather data, as shown in Appendix B.[3] One set is based on using Toronto Pearson International Airport (Toronto) weather data and the other is based on the average weather data for five weather stations across Ontario, namely, Thunder Bay, Windsor, Toronto, Ottawa, and North Bay. The same analysis was also performed in the last Hydro One Transmission rate application (EB-2019-0082) in response to OEB Staff interrogatory Exhibit I, Tab 01, Schedule 151. The results in Appendix B based on the data in this Application support the same conclusion as the earlier

[3] For Hydro One Distribution, the comparison of results using different weather variables is discussed in Exhibit D-05-01

analysis in response to I-01-151, which favours the use of Toronto weather data over using average weather data based on standard regression criteria, as detailed below.

Based on regression results for each model that included a weather variable, the estimated coefficient for weather variable using Toronto weather data is more statistically significant in terms of t Statistics compared to its counterpart using average weather data. Moreover, the estimated coefficients for models using Toronto weather data had improved t Statistic compared to the corresponding figures based on average data in 4 out of 5 of the coefficients for commercial sector, 7 out of 11 of the coefficients in residential sector, and 6 out of 7 coefficients for transportation. The regression results overwhelmingly support the use of Toronto weather data, when modelling aggregate Ontario load by sector. For disaggregated load at each delivery point, as noted in part 4.5, Hydro One uses the local weather station closest to each delivery point, which is the same methodology used in previous transmission rate filings (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2016-0160, and EB-2019-0082).

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 model consists of 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 MODELS

The end-use models cover 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. Appendix C to this Exhibit provides details of the methodology used in the end-use analyses.

In the residential sector, the end-uses analysed include space heating, water heating, air conditioning, and base load. The forecast of each end-use is based on the number of households having that end-use and unit energy consumption of the equipment. The commercial model analyses energy use by building type. Key drivers used in the analysis are the commercial sector floor space and the intensity of end-use demand per unit of floor space. The industrial forecast is based on analysis for each major industrial segment, energy intensity and expected economic growth. The agricultural and transportation sector models are based on base year electricity consumption and the expected growth rates for each sector and segment as determined by the corresponding end-use model.

4.4 METHODOLOGY FOR CUSTOMER FORECAST

Both econometric and customer analyses based on survey results from customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

During February to March 2021 to, Hydro One conducted a customer load forecast survey with customers having more than 5 MW of load. The survey also covered the station service load requirements of generating stations when they are 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 modeled individually using the econometric approach. 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 (reflecting related GDP). The impact on load of weather conditions is also taken into account. The best subset of the drivers is selected on the basis of regression criteria.

For industrial customers, several information sources are used to prepare the forecast. They include:

- 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 provided in the economic forecast.

4.5 METHODOLOGY FOR CUSTOMER DELIVERY POINT FORECAST

This section discusses the forecasting methodology for the customer delivery point forecast. Electricity Power Research Institute's Hourly Electric Load Model (HELM) is used to normalize the hourly load for each of the transmission customer delivery points, removing abnormal weather effects and abnormal load patterns. Key information used in analyzing the load shape for each delivery point includes hourly load and weather data from weather station closest to each delivery point. The weather stations 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[4] is used to retrieve hourly peak electricity 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. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. Hourly weather data is also retrieved to prepare weather sensitivity analysis as discussed in Section 4.1.

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 time of use (weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such are forecast in relation to load on a similar day and hour during the

[4] 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.

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 3 in the next section.

5.0 LOAD FORECAST FOR 2020 TO 2027

Table 3 presents the forecast prepared for this application before and after deducting the load impacts attributed to embedded generation and CDM for the period 2019 to 2027. 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, 2016-0160 and EB-2019-0082. Appendix D to this Exhibit provides the historical actual and weather-corrected charge determinant data for years 2008 to 2020.

Before adjusting for the load impacts arising from embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 22,036 MW in 2021 (12-month average peak), 22,182 MW in 2022, 22,348 MW in 2023, 22,436 MW in 2024, 22,503 MW in 2025, 22,591 MW in 2026, and 22,713 MW in 2027. After deducting the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 19,338 MW in 2021 (12-month average peak), 19,381 MW in 2022, 19,451 MW in 2023, 19,527 MW in 2024, 19,547W in 2025, 19,584 MW in 2026, and 19,607 MW in 2027.

Table 3: Load Forecast Before and After Embedded Generation and CDM
(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand	Network Connection	Line Connection	Transformation Connection
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2019	22,120	22,007	21,220	18,108
2020	21,805	21,582	20,784	17,680
2021	22,036	21,810	20,988	17,854
2022	22,182	21,955	21,146	17,988
2023	22,348	22,119	21,304	18,122
2024	22,436	22,207	21,388	18,194
2025	22,503	22,273	21,452	18,248
2026	22,591	22,360	21,536	18,320
2027	22,713	22,481	21,652	18,418
Load Impact of Embedded Generation				
2019	613	610	476	406
2020	634	628	476	405
2021	671	664	493	419
2022	673	666	495	421
2023	673	666	495	421
2024	673	666	495	421
2025	673	666	495	421
2026	673	666	495	421
2027	673	666	495	421
Load Impact of CDM				
2019	1,931	1,922	1,863	1,590
2020	1,952	1,932	1,872	1,592
2021	2,027	2,007	1,932	1,644
2022	2,128	2,107	2,029	1,726
2023	2,224	2,201	2,120	1,803
2024	2,237	2,214	2,132	1,814
2025	2,283	2,260	2,176	1,851
2026	2,334	2,311	2,225	1,893
2027	2,433	2,409	2,319	1,973
Load Forecast after Deducting Embedded Generation and CDM				
2019	19,575	19,475	18,880	16,111
2020	19,219	19,023	18,435	15,682
2021	19,338	19,140	18,563	15,791
2022	19,381	19,183	18,622	15,841
2023	19,451	19,252	18,689	15,898
2024	19,527	19,327	18,761	15,959
2025	19,547	19,347	18,780	15,975
2026	19,584	19,384	18,816	16,006
2027	19,607	19,406	18,837	16,024

Note: All figures are weather-normal.

The 2023 Ontario Demand forecast is 0.5% lower relative to the currently approved 2022 forecast of 19,543 MW, which was forecast in 2019 as part of EB-2019-0082.

In the year 2020, actual load was 1.9% lower compared to the approved forecast for that year. The reduction is primarily driven by the economic fallout of the COVID-19 pandemic. Many industries were subject to closures in 2020 followed by a gradual reopening of the economy, with some interruptions due to subsequent waves of COVID-19.

The forecast is weather-normal and the actual load could be below or above the forecast depending on unexpected events such as a different economic growth pattern. Table 4 of this Exhibit presents the upper and lower bands associated with one standard deviation for the charge determinant forecast. Based on historical data, there is a two-in-three chance that the actual load between the years 2020 and 2027 will fall within the upper and lower bands. The bands are derived using Monte Carlo simulation technique.

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

Year	Lower Band	Forecast	Upper Band
Network			
2020 (Actual)	19,023	19,023	19,023
2021	18,834	19,140	19,449
2022	18,717	19,183	19,651
2023	18,737	19,252	19,765
2024	18,714	19,327	19,938
2025	18,601	19,347	20,090
2026	18,580	19,384	20,185
2027	18,445	19,406	20,364
Line Connection			
2020 (Actual)	18,435	18,435	18,435
2021	18,267	18,563	18,863
2022	18,170	18,622	19,076
2023	18,189	18,689	19,187
2024	18,166	18,761	19,354
2025	18,056	18,780	19,501
2026	18,035	18,816	19,593
2027	17,904	18,837	19,767
Transformation Connection			
2020 (Actual)	15,682	15,682	15,682
2021	15,539	15,791	16,046
2022	15,456	15,841	16,228
2023	15,473	15,898	16,322
2024	15,453	15,959	16,464
2025	15,360	15,975	16,589
2026	15,342	16,006	16,667
2027	15,230	16,024	16,815

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, using the same load-shape methodology used in this Application. 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 the 2015 row (3rd year forecast) and 2016 row (2nd and 3rd year forecasts) in Table 5 are largely attributable to the load reductions driven by the impact from the expanded Industrial Conservation Initiative (ICI) program, which significantly increased the number of customers eligible to participate in the program. As noted earlier, the economic fallout of the pandemic also reduced load in 2020.

**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	Forecast for current year	Forecast for 2nd Year	Forecast 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%	n.a.
2020	-0.32%	n.a.	n.a.
Mean	0.01%	-0.01%	0.20%
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.
** Last OEB-Approved forecast.*

Between 1999 and 2020, 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 2020-2022 forecasts were approved in proceedings EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2016-0160, and EB-2019-0082. The 2014-2016 load forecast was modified as part of a settlement reached in Hydro One's transmission application EB-2014-0140, which was ultimately approved by the OEB. 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	**Average**
Network	-0.49	-0.45	-0.42	-2.10	0.89	2.46	1.88	**0.25**
Line	-0.71	0.79	0.68	-0.83	1.27	1.84	2.25	**0.76**
Transformation	-1.02	0.16	0.52	-0.37	1.71	2.36	2.27	**0.80**
Average	**-0.74**	**0.17**	**0.26**	**-1.10**	**1.29**	**2.22**	**2.13**	**0.60**
One Standard Deviation (+/-) **	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 forecasts are consistent with one standard deviation.
Note. EB-2014-0140 and EB-2019-0082 approved forecasts were the modified forecast.

As shown in Table 6, the deviations of previous OEB-approved charge determinant forecasts from historical actuals on a weather-corrected basis are well within one standard deviation of error, and the average deviation over the past seven OEB-approved forecasts (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, EB-2016-0160, and EB-2019-0082) 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 2002 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 E

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 E

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 Factors SS parameters:
A[1] 0.0762044 K[1] -0.298107
Non-seasonal
Factors SS parameters:
A[1] 0.364085
K[1] -0.437294

GDPONT LOG 1 1 Exogenous
G[1][1] 0.313288
BPONT[-8] LOG 1 1 Exogenous
G[1][2] 0.00226259
D0803 1 1 Exogenous
G[1][3] -0.0187406

R-squared = 0.994, R-squared corrected for mean = 0.994, Durbin-Watson Statistics = 1.8

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 for 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. As detailed in the main text, for sectors that use weather data as an explanatory variable, there are two sets of results. One set is based on using Toronto Pearson International Airport (Toronto for short) weather data, and the other on the average of weather data for five weather stations across Ontario (Thunder Bay, Windsor, Toronto, Ottawa, North Bay). The results are discussed in Part 4.3.2.

<u>Residential Model</u>

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 2019 (Ui); normalized to be 1 in 2019:

Saturation (t) = (Σ Ei (t) * Ui) / (Σ Ei (2019) * 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 2019.

Usage (t) = [(per household consumption (t))/ Saturation (t)] /
[per household consumption (2019) / Saturation (2019)]

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 times per household consumption in 2019.

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)*(LPELRES(-4)-LPLIQRES(-4)) + C(7)
    *LYPDPHH + C(8)*LHDD^0.5 + (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, IHS GI, 2013 LTEP and Canada Energy Regulator (CER) 2020
- Forecast is from CER 2020 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, IHS GI, 2013 LTEP and CER 2020 Outlook
- Forecast is from CER 2020 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 Statistic Canada, and divided by the number of households / houses based on IHS Global Insight housing starts,

- Forecast is based on forecasts of disposable income from C4SE and Conference Board of Canada, CPI from IHS Global Insight, and number of households is based on consensus forecast of housing starts as presented in Appendix E

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, as presented using actual degree days for the Toronto weather station are shown below:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.063795	0.017215	-3.705717	0.0004
C(2)	0.173859	0.046855	3.710596	0.0003
C(3)	0.610587	0.123816	4.931392	0
C(4)	0.279055	0.115689	2.412119	0.0177
C(5)	-0.038156	0.020273	-1.882062	0.0628
C(6)	-0.020783	0.016169	-1.285372	0.2017
C(7)	0.166639	0.061667	2.702261	0.0081
C(8)	0.124686	0.053861	2.314982	0.0227
C(9)	-0.976652	0.275216	-3.548678	0.0006
C(10)	0.868755	0.265165	3.276282	0.0015
C(11)	-0.002348	0.000673	-3.487404	0.0007

Saturation Model Fit:

R-squared =0.97, Adjusted R-squared = 0.96, Durbin-Watson Statistics =2.09

Usage Model Fit:

R-squared =0.96, Adjusted R-squared = 0.95, Durbin-Watson Statistics =2.10

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 84% 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.

Using average degree days from multiple weather stations instead of actual degree day for Toronto, we obtain the following results:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.064482	0.017177	-3.753993	0.0003
C(2)	0.175761	0.046751	3.759495	0.0003
C(3)	0.617538	0.12292	5.023896	0
C(4)	0.27305	0.114761	2.379302	0.0193
C(5)	-0.038172	0.02006	-1.902924	0.06
C(6)	-0.020646	0.016665	-1.238948	0.2184
C(7)	0.124909	0.064666	1.931613	0.0563
C(8)	0.08803	0.053887	1.633604	0.1056
C(9)	-0.868674	0.280948	-3.091934	0.0026
C(10)	0.769616	0.270359	2.846638	0.0054
C(11)	-0.001815	0.00065	-2.791952	0.0063

Saturation Model Fit:

R-squared =0.97, Adjusted R-squared = 0.96, Durbin-Watson Statistics =2.10

Usage Model Fit:

R-squared =0.95, Adjusted R-squared = 0.95, Durbin-Watson Statistics =2.12

Commercial Model

The commercial model uses the price of electricity and of natural gas, commercial GDP and cooling and 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, IHS GI, 2013 LTEP and CER 2020 Outlook
- Forecast is from CER 2020 Outlook

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

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and CER 2020 Outlook
- Forecast is from CER 2020 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 E

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 based on using Toronto degree days is presented below:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.021769	0.005404	-4.028038	0.0002
C(2)	0.089847	0.022817	3.93765	0.0003
C(3)	0.878405	0.025296	34.72499	0
C(4)	0.03098	0.013252	2.33784	0.0234
C(5)	0.115097	0.122497	0.93959	0.3519

R-squared =0.997, Adjusted R-squared = 0.997, Durbin-Watson Statistics =2.06

The regression results reflect a high goodness fit and statistical significance for all estimates at 65% probability level or higher.

The estimated equation based on using average degree days from multiple weather stations is:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.018842	0.005555	-3.392141	0.0014
C(2)	0.084496	0.023785	3.552514	0.0008
C(3)	0.883787	0.025664	34.43739	0
C(4)	0.034282	0.014764	2.321987	0.0243
C(5)	0.124947	0.122801	1.017481	0.3138

R-squared =0.998, Adjusted R-squared = 0.997, Durbin-Watson Statistics =2.08

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

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, IHS GI, 2013 LTEP and CER 2020 Outlook
- Forecast is from Global Insight for coal and CER 2020 Outlook for other energy prices, include 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 E

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

The estimated model is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	2.3085	0.928608	2.485979	0.0168
C(2)	0.628776	0.115571	5.440583	0
C(3)	-0.522669	0.121784	-4.291765	0.0001
C(4)	0.744306	0.071764	10.37158	0
C(5)	-0.042759	0.018963	-2.254917	0.0292
C(6)	-0.160032	0.044662	-3.583133	0.0008

R-squared =0.867, Adjusted R-squared = 0.852, Durbin-Watson Statistics =2.05

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(20)*DCR+C(5)*LT
+[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(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 are 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, IHS GI, 2013 LTEP and CER 2020 Outlook
- Forecast is from Global Insight for price of coal and CER 2020 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,

DCR=dummy variable to account for closure of coal-fired generating stations in Ontario. It reflects share of reduction in each year in total reduction based on the generating capacity: equals 0 prior to 2005, 0.15 for the years 2005-2009, 0.41 in 2010, 0.54 in 2011, 0.57 in 2012, 0.96 in 2013, and 1 in 2014 and after.

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)	-2.054559	0.12838	-16.00374	0
C(12)	-0.92905	0.0477	-19.47692	0
C(13)	-1.258657	0.079038	-15.92474	0
C(23)	-0.738102	0.10658	-6.92534	0
C(20)	0.426706	0.183953	2.319647	0.0224
C(5)	0.551642	0.034283	16.09093	0
C(60)	0.512871	0.068233	7.516466	0
C(2)	-0.739887	0.128897	-5.740129	0
C(6)	0.412636	0.032229	12.80328	0
C(7)	0.222612	0.035162	6.331056	0

LW13 Model Fit:
R-squared =0.993, Adjusted R-squared = 0.992, Durbin-Watson Statistics =2.05

LW23 Model Fit:
R-squared =0.993, Adjusted R-squared = 0.993, Durbin-Watson Statistics =1.90

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(-3+C(3)*D08+AR(1)+MA(4)

where

ELAGR = electricity consumption in Ontario agricultural sector,

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

POPONT = Ontario population,

- History is from Statistics Canada
- Forecast is from C4SE and Conference Board of Canada

TREND = a trend variable, equals 1 in 1961 and increases by 1 per year thereafter,

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

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

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

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2276.405	174.4256	13.05087	0
D(POPONT(-3))	1.436576	0.716454	2.005118	0.0555
D08	248.3595	83.94327	2.95866	0.0065
AR(1)	0.670984	0.154288	4.348905	0.0002
MA(4)	0.957648	0.024835	38.56091	0

R-squared =0.769, Adjusted R-squared = 0.734, Durbin-Watson Statistics =2.28

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)*CDD+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, IHS GI, 2013 LTEP and (CER) 2020
- Forecast is from CER 2020 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, IHS GI, 2013 LTEP and (CER) 2020
- Forecast is from CER 2020, includes carbon tax

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

CDD = 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 based on Toronto degree days is:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	1.956057	0.637405	3.068781	0.0044
C(2)	0.692364	0.09486	7.298801	0
C(3)	-0.111478	0.058921	-1.891993	0.0679
C(4)	0.17746	0.061827	2.870265	0.0073
C(5)	0.000472	0.000143	3.307989	0.0024
C(6)	-0.516835	0.091171	-5.668852	0
C(7)	0.336721	0.08811	3.821605	0.0006

R-squared =0.830, Adjusted R-squared = 0.797, Durbin-Watson Statistics =2.16

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.

Regression results based on average degree days from multiple weather stations is:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	1.72128	0.629429	2.73467	0.0102
C(2)	0.720821	0.093743	7.689337	0
C(3)	-0.074534	0.056287	-1.324182	0.1951
C(4)	0.172836	0.062485	2.766047	0.0095
C(5)	0.000667	0.000212	3.143746	0.0037
C(6)	-0.525792	0.092846	-5.663079	0
C(7)	0.330582	0.08955	3.691576	0.0009

R-squared =0.825, Adjusted R-squared = 0.791, Durbin-Watson Statistics =2.12

APPENDIX C

END-USE MODEL

Residential Sector

The end-uses considered in the residential sector include space heating, water heating, air conditioning and base load (lighting and appliances). The forecast of each of the end-use is based on the following equation:

kWh = number of households * end-use share * end-use UEC

where:

- end-use share refers to the fraction of houses with the particular end-use considered,
- UEC (unit energy consumption) refers to the annual energy consumption of that end-use per household.

The following section describes each component of the equation in detail.

- The base-year number of households was taken from Ontario residential household information from Statistics Canada.
- The base year end-use shares (space heating, water heating and air conditioning) information and fuel switching (space/water heating) information are based on Statistics Canada residential appliance survey results.
- The trends for end-use shares and fuel switching over the forecasting period are based on historical time series from Statistics Canada residential appliance surveys.
- The base year end-use UEC's were estimated based on Statistics Canada Ontario residential electricity consumption data (CANSIM DATA) and Statistics Canada residential appliance survey results.

Commercial Sector

The commercial forecast for the total transmission system is developed using the COMMEND (Commercial end-use planning system). The model uses an end-use framework to provide estimates of energy use by building type. The 12 building types include office, elementary and secondary school, college and universities, health, public service, retail, grocery, accommodation, recreation, religious/cultural, warehouse and commercial miscellaneous. Non-building related segments, such as transportation, communication and utilities etc., were prepared outside the model using spreadsheet analysis. The forecast is the product of the commercial sector building floor space and the intensity of end-use demand per unit floor space.

Industrial Sector

Industrial sector analysis includes large industrial customers with monthly demand >5 MW and general service customers with demand <5 MW. The forecast is based on detailed analysis of each major industrial sub-sector. Various segments are considered in this analysis, including abrasives, motor vehicle assembly, vehicle parts, non-metallic minerals, electronic products, fabricated metal products, foods & beverage, glass, industrial chemicals, iron and steel, lime, smelting & mining, petroleum refining, pulp and paper, rubber and plastics, clothing and textiles, and miscellaneous manufacturing. The forecast for industrial customers is based on customer level data and the effect of the economy on their production prospects. Pattern in energy intensity is considered in relation to technological change.

Agricultural and Transportation Sectors

Transportation sector is comprised mainly of pipeline transport and road transport. The forecast for the agricultural and transportation sectors is based on the following equation:

kWh = base year consumption * expected annual growth rates

For each component of this equation, data is gathered from:

- The base year consumption by segment is taken from the Statistics Canada;
- Expected annual growth rates are determined by the corresponding end-use model.

APPENDIX D

HISTORICAL ONTARIO DEMAND AND CHARGE DETERMINANT DATA

This Appendix provides the historical actual and weather corrected Ontario demand and Hydro One charge determinants for 2008-2020.

Actual Ontario Demand and Hydro One Charge Determinants
(MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008												
Ontario Demand	22,782	23,054	20,990	19,512	18,650	24,195	23,787	22,707	22,975	19,366	21,279	22,541
Network Connection	22,112	22,227	20,395	19,114	18,260	23,502	23,302	22,182	22,502	19,183	20,740	22,169
Line Connection	21,148	21,065	19,719	18,564	17,836	22,514	22,414	21,218	21,255	18,390	19,574	20,940
Transformation Connection	18,500	18,472	17,093	15,912	15,057	19,316	19,368	18,269	18,263	15,717	16,953	18,418
2009												
Ontario Demand	22,983	22,110	21,466	18,744	17,560	22,540	20,011	24,380	19,731	18,420	19,710	21,921
Network Connection	22,414	21,446	21,194	18,461	17,647	22,053	20,089	23,705	19,343	18,011	19,413	21,146
Line Connection	21,084	20,175	20,262	17,799	17,170	20,795	19,042	22,244	18,520	17,249	18,160	19,968
Transformation Connection	18,568	17,898	17,701	15,481	14,705	18,166	16,687	19,622	16,182	15,118	16,009	17,856
2010												
Ontario Demand	22,045	21,367	19,393	17,398	22,904	21,527	25,075	24,917	24,444	17,704	19,970	22,114
Network Connection	21,656	20,845	18,931	17,360	22,162	21,181	24,903	24,227	24,108	17,640	19,477	21,868
Line Connection	20,381	19,594	18,280	17,049	21,143	20,338	23,589	22,945	22,527	17,174	18,607	20,312
Transformation Connection	18,106	17,268	15,747	14,533	18,394	17,698	20,736	19,991	19,601	14,732	15,969	17,841
2011												
Ontario Demand	22,733	21,871	20,667	17,945	20,870	22,765	25,450	22,051	21,552	18,234	19,673	20,204
Network Connection	21,844	21,184	20,115	17,737	20,647	22,661	25,395	21,831	21,398	18,104	19,450	19,964
Line Connection	20,629	19,927	19,023	17,396	19,764	21,620	24,252	21,411	20,551	17,569	18,576	19,331
Transformation Connection	18,115	17,394	16,433	14,811	16,858	18,582	21,077	18,454	17,671	15,006	16,057	16,827
2012												
Ontario Demand	21,847	19,956	20,332	17,874	21,106	24,107	24,636	23,188	21,183	18,829	20,144	20,382
Network Connection	21,175	19,441	19,874	17,564	20,977	24,135	24,818	22,865	21,021	18,662	19,749	20,136
Line Connection	19,931	19,057	18,768	17,310	20,276	23,193	23,700	21,922	20,294	18,024	18,877	19,211
Transformation Connection	17,382	16,436	16,085	14,645	17,298	20,147	20,693	19,033	17,528	15,363	16,304	16,588
2013												
Ontario Demand	22,610	21,426	19,825	18,854	20,488	22,662	24,927	22,833	22,682	18,445	20,615	22,556
Network Connection	21,960	20,995	19,670	18,649	20,570	22,835	25,403	22,793	22,740	18,418	20,355	21,837
Line Connection	20,570	19,836	18,700	17,978	19,633	21,834	24,189	21,810	21,988	18,060	19,495	20,767
Transformation Connection	17,931	17,219	15,949	15,209	16,674	18,757	20,904	18,810	18,850	15,318	16,795	18,018
2014												
Ontario Demand	22,774	21,905	21,656	18,557	18,844	20,807	21,300	21,363	21,123	17,784	20,102	20,938
Network Connection	22,636	21,426	21,232	18,317	18,858	21,260	21,742	21,875	21,975	17,734	20,150	20,507
Line Connection	21,450	20,285	19,903	17,697	18,385	20,738	21,171	20,980	21,247	17,455	19,255	19,553
Transformation Connection	18,731	17,553	17,265	15,119	15,445	17,579	17,974	17,954	18,151	14,841	16,605	16,862
2015												
Ontario Demand	21,814	21,494	20,827	18,462	19,158	19,339	22,516	22,383	22,063	17,667	19,239	19,161
Network Connection	21,762	21,707	20,597	18,212	19,475	19,351	22,931	22,880	22,347	17,575	18,927	18,841
Line Connection	20,722	20,983	19,639	17,531	19,019	19,057	22,275	22,195	22,251	17,374	18,278	18,619
Transformation Connection	18,017	18,234	16,999	14,898	15,992	16,077	19,151	19,014	19,118	14,612	15,473	15,839
2016												
Ontario Demand	20,836	20,766	20,063	17,821	19,885	21,692	22,659	23,100	23,213	18,189	19,369	20,688
Network Connection	20,219	20,161	19,698	17,993	19,786	22,311	23,193	23,551	23,413	17,919	18,866	20,445
Line Connection	19,422	19,438	18,808	17,547	19,800	21,779	22,715	23,141	22,568	17,528	18,113	19,470
Transformation Connection	16,643	16,718	15,955	14,768	16,657	18,449	19,379	19,759	19,294	14,844	15,321	16,698
2017												
Ontario Demand	20,372	19,838	19,174	17,349	17,738	21,168	20,627	20,158	21,786	17,418	19,115	20,306
Network Connection	19,797	19,176	18,955	17,137	17,880	21,189	20,996	21,073	22,159	17,501	18,999	20,432
Line Connection	19,131	18,466	18,436	16,648	17,611	20,457	20,805	20,603	21,566	17,141	18,124	19,785
Transformation Connection	16,403	15,727	15,706	13,992	14,761	17,480	17,672	17,555	18,563	14,575	15,452	17,078
2018												
Ontario Demand	20,906	20,076	18,462	18,011	20,473	21,369	23,046	21,990	23,240	18,205	20,152	19,891
Network Connection	20,955	19,488	18,271	18,035	20,690	21,752	23,756	22,806	23,613	18,599	19,682	19,375
Line Connection	20,178	18,792	17,649	17,603	20,578	21,843	23,084	22,177	22,971	18,240	18,675	18,691
Transformation Connection	17,413	16,122	15,057	14,913	17,505	18,600	19,930	19,220	19,670	15,422	15,961	15,999
2019												
Ontario Demand	21,525	20,500	20,263	17,645	16,784	20,248	21,791	21,354	19,717	18,329	19,625	20,974
Network Connection	21,035	20,235	19,855	17,455	16,770	20,283	22,585	21,665	19,502	18,323	19,406	20,346
Line Connection	20,380	19,528	18,795	16,992	16,370	19,728	22,398	21,095	19,125	17,884	18,479	19,380
Transformation Connection	17,609	16,724	16,030	14,323	13,773	16,686	19,181	18,066	16,263	15,188	15,874	16,728
2020												
Ontario Demand	19,928	19,630	18,183	15,350	20,649	21,292	24,446	23,823	20,225	17,679	19,147	20,738
Network Connection	19,452	19,409	17,946	15,511	20,364	21,062	24,552	23,517	20,135	17,452	18,919	20,333
Line Connection	18,866	18,700	17,455	15,012	19,876	21,077	23,767	22,640	19,415	17,018	18,215	19,244
Transformation Connection	16,177	15,974	14,716	12,574	16,829	17,973	20,432	19,501	16,426	14,240	15,482	16,471

Weather Corrected Ontario Demand and Hydro One Charge Determinants
(MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008												
Ontario Demand	23,409	23,058	21,009	19,967	18,559	22,677	22,847	22,848	20,436	19,562	21,577	22,937
Network Connection	22,721	22,231	20,414	19,559	18,171	22,027	22,381	22,319	20,015	19,377	21,030	22,558
Line Connection	21,728	21,067	19,736	18,996	17,748	21,099	21,527	21,348	18,904	18,575	19,846	21,305
Transformation Connection	19,005	18,471	17,105	16,279	14,980	18,100	18,599	18,378	16,241	15,872	17,186	18,737
2009												
Ontario Demand	22,639	22,128	21,246	18,635	18,943	22,935	23,575	23,639	20,224	19,466	20,671	21,977
Network Connection	22,078	21,464	20,977	18,353	19,037	22,439	22,668	22,984	19,827	19,034	20,360	21,199
Line Connection	20,768	20,191	20,054	17,696	18,522	21,159	21,322	21,568	18,983	18,229	19,045	20,019
Transformation Connection	18,290	17,913	17,520	15,391	15,863	18,485	18,259	19,026	16,587	15,976	16,789	17,901
2010												
Ontario Demand	21,817	21,551	20,413	18,082	18,373	21,760	23,144	22,299	20,901	18,275	19,881	21,709
Network Connection	21,432	21,025	19,927	18,042	17,778	21,411	22,986	21,681	20,614	18,209	19,389	21,467
Line Connection	20,170	19,763	19,242	17,719	16,960	20,558	21,773	20,535	19,262	17,728	18,524	19,940
Transformation Connection	17,919	17,417	16,575	15,104	14,755	17,890	19,140	17,891	16,760	15,207	15,898	17,514
2011												
Ontario Demand	21,964	21,734	20,621	18,062	18,114	21,349	22,728	21,671	20,655	18,262	19,977	21,427
Network Connection	21,104	21,052	20,070	17,853	17,920	21,252	22,679	21,454	20,508	18,131	19,750	21,173
Line Connection	19,931	19,803	18,980	17,509	17,153	20,275	21,658	21,042	19,696	17,596	18,864	20,501
Transformation Connection	17,502	17,285	16,397	14,908	14,632	17,426	18,823	18,136	16,936	15,029	16,305	17,846
2012												
Ontario Demand	21,233	21,188	20,169	17,638	18,118	21,463	22,735	21,905	20,743	18,208	19,529	21,253
Network Connection	20,579	20,641	19,714	17,332	18,007	21,488	22,902	21,600	20,585	18,047	19,145	20,996
Line Connection	19,370	20,233	18,617	17,082	17,406	20,648	21,871	20,709	19,873	17,430	18,300	20,031
Transformation Connection	16,893	17,450	15,956	14,451	14,849	17,937	19,095	17,980	17,165	14,856	15,805	17,297
2013												
Ontario Demand	21,696	21,609	20,242	18,035	18,223	21,058	22,434	21,470	20,575	18,181	19,609	21,191
Network Connection	21,072	21,175	20,084	17,838	18,296	21,218	22,862	21,432	20,628	18,155	19,362	20,515
Line Connection	19,738	20,005	19,094	17,197	17,462	20,288	21,770	20,508	19,946	17,802	18,544	19,510
Transformation Connection	17,206	17,366	16,284	14,548	14,831	17,429	18,813	17,687	17,100	15,099	15,976	16,928
2014												
Ontario Demand	21,998	21,694	20,488	18,335	18,207	21,378	22,719	21,708	20,552	18,364	19,856	21,350
Network Connection	21,866	21,211	20,082	18,094	18,217	21,839	23,185	22,223	21,377	18,308	19,899	20,906
Line Connection	20,530	19,904	18,651	17,320	17,595	21,105	22,367	21,117	20,477	17,853	18,840	19,748
Transformation Connection	17,927	17,226	16,181	14,798	14,773	17,893	18,992	18,074	17,496	15,182	16,249	17,034
2015												
Ontario Demand	22,038	20,124	20,005	18,580	17,554	20,798	22,710	22,039	20,244	18,183	19,708	20,454
Network Connection	21,985	20,323	19,784	18,329	17,845	20,811	23,128	22,528	20,509	18,089	19,384	20,112
Line Connection	20,819	19,537	18,759	17,546	17,331	20,382	22,343	21,732	20,306	17,783	18,616	19,766
Transformation Connection	18,098	16,974	16,235	14,907	14,569	17,191	19,206	18,615	17,456	14,952	15,755	16,817
2016												
Ontario Demand	21,460	20,931	20,403	17,779	18,542	21,370	22,579	21,365	20,550	18,167	19,390	20,753
Network Connection	21,102	20,611	20,114	17,656	18,618	21,683	23,040	21,706	20,880	18,057	19,136	20,333
Line Connection	20,031	19,697	19,091	17,074	18,183	21,101	22,331	20,994	20,324	17,748	18,366	19,546
Transformation Connection	17,384	17,050	16,390	14,477	15,325	17,921	19,126	17,995	17,406	15,025	15,687	16,799
2017												
Ontario Demand	20,674	20,992	18,863	17,693	16,742	20,491	21,906	20,897	20,369	17,515	19,808	20,408
Network Connection	20,331	20,601	18,578	17,565	16,827	20,757	22,347	21,477	20,771	17,436	19,581	20,190
Line Connection	19,449	19,780	17,736	17,019	16,561	20,248	21,875	20,884	20,249	17,133	18,774	19,495
Transformation Connection	16,810	17,042	15,221	14,406	13,913	17,174	18,655	17,847	17,359	14,513	15,993	16,736
2018												
Ontario Demand	20,323	19,699	18,913	17,516	18,516	21,128	21,747	21,093	19,810	17,843	19,152	20,147
Network Connection	20,028	19,295	18,672	17,452	18,656	21,382	22,240	21,748	20,080	17,872	18,810	19,904
Line Connection	19,237	18,611	17,957	16,952	18,454	21,012	21,759	21,238	19,607	17,545	18,003	19,275
Transformation Connection	16,577	16,001	15,349	14,320	15,552	17,843	18,634	18,196	16,819	14,842	15,301	16,516
2019												
Ontario Demand	20,216	19,697	19,060	17,471	18,263	20,924	21,601	21,007	19,671	17,833	19,027	20,135
Network Connection	19,756	19,442	18,675	17,283	18,247	20,961	22,388	21,313	19,456	17,827	18,815	19,533
Line Connection	19,141	18,763	17,679	16,825	17,812	20,387	22,202	20,753	19,080	17,400	17,916	18,605
Transformation Connection	16,539	16,069	15,078	14,182	14,987	17,243	19,014	17,773	16,224	14,777	15,391	16,059
2020												
Ontario Demand	20,347	19,912	18,930	15,567	17,696	20,513	21,197	20,712	19,547	17,349	18,863	19,997
Network Connection	19,861	19,688	18,683	15,731	17,453	20,291	21,288	20,446	19,460	17,126	18,639	19,606
Line Connection	19,263	18,969	18,172	15,224	17,034	20,306	20,608	19,684	18,765	16,700	17,945	18,556
Transformation Connection	16,518	16,203	15,321	12,752	14,422	17,316	17,716	16,955	15,876	13,974	15,253	15,882

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-2014-00140, EB-2016-0160, and EB-2019-0082).

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 Connection 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)	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
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	19,888							3.06
Average Excluding First Year (Actual) (8)										-0.49	-0.45	-0.42	-2.10	0.89	2.46	1.88

(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.
(8) 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, and EB-2019-0082 forecast).

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

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)	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
	12-Month Average in MW									Difference from Actual Weather Corrected (%) (5)						
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	19,274							3.45
Average Excluding First Year (Actual) (8)										-0.71	0.79	0.68	-0.83	1.27	1.84	2.25

(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.
(8) 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, and EB-2019-0082 forecast).

Table 6c
Historical Board Approved for Transforer Connection Forecast
vs. Historical Actual and Historical 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)	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
	12-Month Average in MW									Difference from Actual Weather Corrected (%) (5)						
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	16,400							3.63
Average Excluding First Year (Actual) (8)										-1.02	0.16	0.52	-0.37	1.71	2.36	2.27

(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.
(8) 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, and EB-2019-0082 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 latest Hydro One consultation with IESO in 2021 as well as an earlier joint study between the two organizations as documented in EB-2008-0272 (Exhibit A-14-03, Attachment B).

Over the 17-month forecast period starting in February 2021, for which IESO has a monthly peak forecast, the difference between IESO and Hydro One forecasts averages to 658 MW. Following the same methodology as in the joint study between Hydro One and IESO noted above, sources of difference can be shown to be basically 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 non-weather related load is low compared to other days. Due to reliability concerns, IESO assumes that the 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 February 2021 to June 2022 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 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 (= 650 + 300) MW. Comparing the latter figure with the actual difference between the two forecast (658 MW) reveals that Hydro One's forecast is actually higher by 292 MW compared to the IESO forecast over the February 2021 to June 2022 period.

APPENDIX G

YEAR-OVER-YEAR COMPARISON OF LOAD

This Appendix provides year-over-year comparison of load weather-normalized over historical, bridge year (2019) and test years.

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

			Charge Determinants					
Year	Ontario Peak	% Change	Network	% Change	Line Connection	% Change	Transformation Connection	% Change
2008	21,574	0.5	21,067	0.7	20,156	0.6	17,413	0.5
2009	21,340	-1.1	20,868	-0.9	19,796	-1.8	17,333	-0.5
2010	20,684	-3.1	20,330	-2.6	19,348	-2.3	16,839	-2.9
2011	20,547	-0.7	20,245	-0.4	19,417	0.4	16,769	-0.4
2012	20,348	-1.0	20,086	-0.8	19,298	-0.6	16,645	-0.7
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	19,338	0.6	19,140	0.6	18,563	0.7	15,791	0.7
2022	19,381	0.2	19,183	0.2	18,622	0.3	15,841	0.3
2023	19,451	0.4	19,252	0.4	18,689	0.4	15,898	0.4
2024	19,527	0.4	19,327	0.4	18,761	0.4	15,959	0.4
2025	19,547	0.1	19,347	0.1	18,780	0.1	15,975	0.1
2026	19,584	0.2	19,384	0.2	18,816	0.2	16,006	0.2
2027	19,607	0.1	19,406	0.1	18,837	0.1	16,024	0.1

This page left blank intentionally.

DATA FOR HYDRO ONE TRANSMISSION LOAD FORECAST

This exhibit has been filed separately in MS Excel format.

DISTRIBUTION LOAD FORECAST AND METHODOLOGY

1.0 INTRODUCTION

This Exhibit discusses Hydro One Distribution's load forecast and methodology. The load forecast provides information on total distribution load and number of customers. This information is used for the purpose of setting distribution rates.

Hydro One Distribution uses a number of methods, such as econometric models, end-use models, 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 section are weather-normal, and the numbers are at the wholesale level unless otherwise specified. Abnormal weather effects are removed from the base year 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 in past 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, and EB-2017-0049).

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.

Hydro One Distribution's load forecasting team has significant experience in preparing provincial and local electricity demand forecasts and load profiles. The load forecast methodology described in this Exhibit is the same as Hydro One's previous distribution rate cases (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, EB-2013-0416, and EB-2017-0049). Since the restructuring of Ontario Hydro into its successor companies, the performance of Hydro One Distribution's system load forecast has been accurate, as shown in Table 1.

Between 1997 and 2001, the average variance of customers' energy purchase forecast compared to the weather corrected actual energy consumed is within one standard deviation of the forecast, despite large variances resulting from unusual events such as the ice storm in 1998 and September 11, 2001. One standard deviation, an accepted standard in the utility industry, signifies there is a one-in-three chance that the actual will be outside the plus or minus range; (alternatively, there is a two-in-three chance that the actual will fall within the plus or minus range). The performance of the forecast in subsequent years, namely 2002 to 2020, shows that the forecast is well within one standard deviation band for the corresponding energy purchases.

Table 2 compares the accuracy of the load forecast for retail customers approved in the last distribution rate case (EB-2017-0049) with the weather corrected actuals. Detailed comparisons between the forecasts provided in the previous Hydro One Distribution rate applications (EB-2005-0378, EB-2007-0681 EB-2009-0096, EB-2013-0416, and EB-2017-0049) with the weather corrected actuals are presented in Appendix E to this Exhibit, Table E.2.

Table 1 - Comparison of Hydro One Distribution Forecast with Actual

(Variance of forecast expressed as percent of actual on weather corrected basis)

Forecast made for Plan Year	Variance for Plan Year	Variance for 2nd Year	Variance for 3rd Year
1997	0.12	-2.03	1.91
1998	-2.03	-3.39	-2.02
1999	-0.85	0.73	-0.15
2000	0.46	-0.03	0.76
2001	-1.80	-1.56	-2.44
2002	1.80	2.39	2.12
2003	-0.82	-1.37	-0.74
2004	0.14	0.62	0.76
2005	0.25	0.12	0.46
2006	-0.06	-0.12	0.99
2007	-0.09	0.93	1.59
2008	-0.57	0.54	0.7
2009	-0.14	-0.25	-0.78
2010	1.24	0.28	-0.73
2011	0.22	0.34	-0.24
2012	0.54	-0.51	0.32
2013	-0.39	0.15	0.46
2014	0.72	1.45	2.71
2015	0.6	1.81	4.66
2016	0.07	2.16	3.56
2017	0.77	2.17	1.92
2018	0.49	-0.52	-0.75
2019	-0.74	-0.97	N.A.
2020	-0.48	N.A.	N.A.
Mean (1997-2001)	-0.82	-1.26	-0.39
One standard deviation (+/-)	1.13	2.57	3.00
Mean (2002-2020)	0.20	0.51	1.00
One standard deviation (+/-)	1.18	2.53	2.90

* *Note: The forecast performance pertains to Hydro One retail purchases.*

Table 2 – Comparison of 2017 Forecast with Actual (GWh)

	Retail Forecast	Weather Corrected Actual	Variance (%)
2018	19,372	19,277	0.49
2019	19,106	19,207	-0.52
2020	19,006	19,149	-0.75

Exhibit D-03-01 discusses in detail the various economic factors taken into consideration when applying the methodology for deriving the load forecasts. Actual load is presented in Attachment D-05-01-01.

Hydro One Distribution's forecasting methodology uses 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, efficiency improvement standards, and conservation and demand management (CDM) assumptions. Economic inputs were based on analyses prepared by major economic institutions, such as IHS Global Insight, Conference Board of Canada, Centre for Spatial Economics, University of Toronto, Canada Mortgage and Housing Corporation, and Altus Group. Inputs from the institutions noted above form the economic database (hereinafter, the "economic forecast") that is used to establish Hydro One Distribution's load forecast.

Section 3 of this Exhibit details the methodology Hydro One uses to develop its load forecasts. Detailed modeling equations and definitions are presented in the Appendices to this Exhibit.

Using Hydro One Distribution's previously approved forecasting methodology, the forecast for the period 2021 – 2027 is presented below:

Table 3 - Hydro One Distribution Load and Number of Customers

Year	GWh Delivered Forecast	Distribution Customer Count
2021	34,785	1,333,269
2022	34,907	1,343,110
2023 *	35,854	1,413,905
2024 *	35,974	1,424,106
2025 *	36,090	1,434,135
2026 *	36,202	1,443,532
2027 *	36,312	1,452,813

* The figures include the impact of integrating Acquired Utilities into Hydro One Distribution.

The figures in Table 3 for 2023 onwards reflect the impact of integrating load and customer numbers of Norfolk, Haldimand and Woodstock (Acquired Utilities) into Hydro One Distribution. Section 4 provides a detailed discussion comparing forecasts for 2023 to 2027 with historic years 2019 to 2020 and bridge years 2021 to 2022.

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, for the most part, based on the relationship between major economic drivers and electricity demand over the forecast period 2023 to 2027. 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.

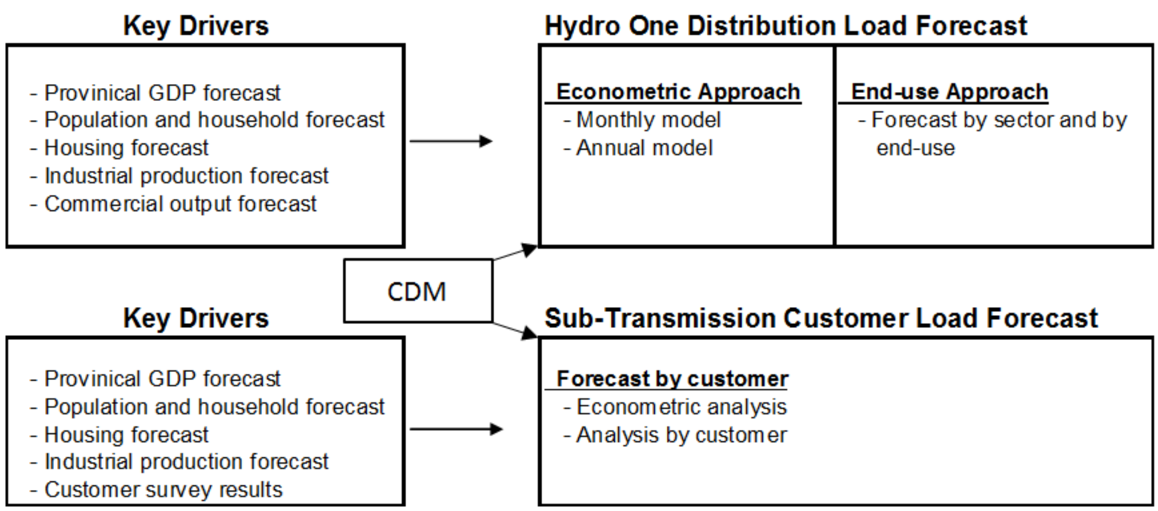


Figure 1: Factors Affecting Distribution Load Forecast

Key information used in the analysis includes the Ontario GDP, provincial demographic, industrial production and commercial output forecasts and regional analysis included in the economic forecast. Also taken into consideration are CDM, which have 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 February 2021. The load forecast also takes into account 2020 actual load and CDM information consistent with the 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 4 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, Table E.8.

Table 4 - CDM Impact on Hydro One Distribution Load
(GWh)

Year	Retail Customers	ST Customers Direct	ST Customers LDC	Total
2019	2,154	247	1,043	3,444
2020	2,174	255	1,027	3,456
2021	2,315	273	1,094	3,681
2022	2,466	291	1,165	3,922
2023*	2,777	330	1,235	4,343
2024*	2,833	338	1,260	4,431
2025*	2,859	342	1,271	4,472
2026*	2,867	344	1,275	4,486
2027*	3,055	367	1,359	4,781

Note. All figures are weather-normal.
* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

The CDM figures for all years are consistent with IESO Annual Planning Outlook (APO), including the load impact of LDC energy efficiency programs for the years 2019-2020. The methodology for incorporating CDM into the load forecast is described in Section 3 of this Exhibit.

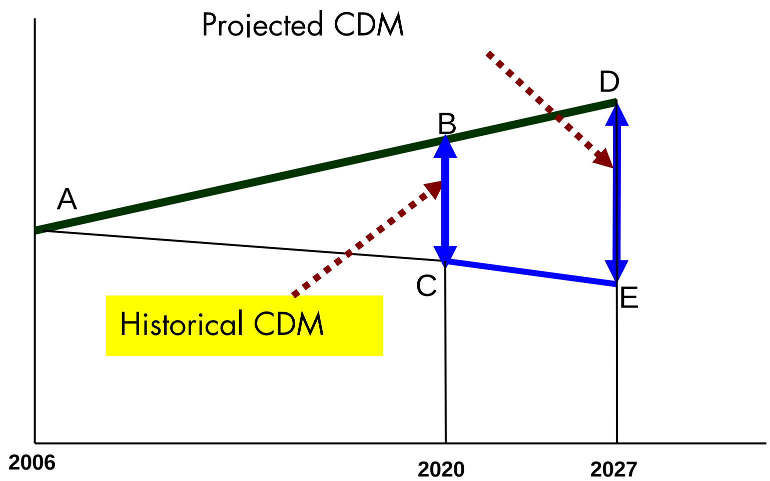
2.2 CUSTOMER FORECAST

Hydro One's distribution system served about 1.314 million customers in 2019 and 1.323 million customers in 2020. The customer base is forecast to reach 1.333, and 1.343 million, respectively, over the 2021 to 2022 period. With the integration of the Acquired Utilities, the customer base is forecast to increase to 1.414 million in 2023, and 1.424, 1.434, 1.444, and 1.453 million over the years 2024 to 2027, respectively. 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 is developed on an as-required basis to support the annual business planning process, system development plans, and rate submissions to the Board. Active customer accounts and service points are used as the basis to prepare the customer forecast by rate class. 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 averaged about 10,000 per year from 2015 to 2020, which is consistent with the economic conditions during that period. Customer growth for the forecast period, excluding the Acquired Utilities, is expected to remain the same over the 2021 to 2027 period. In addition, starting in 2023 about 61,000 customers from the Acquired Utilities are added to the customer forecast. Details of the customer forecast by rate class over the forecast period are provided in Appendix E, Table E.3.

3.0 LOAD FORECASTING METHODOLOGY

Hydro One Distribution's load forecast is developed using both econometric and end-use approaches. The load impacts of CDM are added back to the historical values during the modeling process (see Figure 2 below).



A: 2006 actual load

B: Estimated Load without CDM impacts in 2020

C: 2020 actual load

D: Projected load without CDM impacts in 2027

E: Projected load with CDM impacts in 2027

Figure 2: Incorporation of CDM in the Load Forecast

The forecast base-year is corrected for abnormal weather conditions and the forecast growth rates are applied to the normalized base-year value. The forecast is weather-normal in that it predicts the future load under normal weather conditions.

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-case load data, from which the load forecast will be developed. The volatility of abnormal or extreme weather conditions can adversely impact the ability to provide a consistent and meaningful forecast for load growth. 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 Distribution is a proven technique that has performed well in the past years. The same methodology was reviewed and approved by the OEB in the Distribution Cost Allocation Review (EB-2005-0378) and in previous Hydro One Distribution Rate applications (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, EB-2013-0416, and EB-2017-0049).

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 cover and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction is best be done on a daily basis, rather than 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 of time. 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 of time.

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. 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

Both econometric (top-down) and end-use (bottom-up) models are used to prepare the load forecast for Hydro One Distribution. Both monthly and annual econometric models are used to forecast Hydro One Distribution's total distribution system load. End-use models are used to analyse the distribution system load by customer rate class. Key information used in the analysis includes economic, demographic, industrial production and commercial output forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set of data when looked at from macro (econometric) and micro (end-use) perspectives. The load impacts of CDM are added back to the historical data set during the modelling process.

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 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 provides the detailed regression equations and definitions.

In the OEB Decision in EB-2017-0049, Hydro One was directed to carry out further investigation on the use of weather data from multiple locations in the province. In response to the OEB's direction, Hydro

One compared two sets of regression results for annual econometric models, as shown in Appendix B. One set is based on using Toronto Pearson International Airport (Toronto) weather data and the other on the average weather data for five weather stations across Ontario, namely, Thunder Bay, Windsor, Toronto, Ottawa, and North Bay. The same analysis was performed in the last Hydro One Transmission rate proceeding (EB-2019-0082) in response to OEB Staff interrogatory Exhibit I, Tab 01, Schedule 151. The results in Appendix B based on the data in this application support the same conclusion as the earlier analysis in I-01-151 of EB-2019-0082. In all cases, the standard regression criteria results favour the use of Toronto weather data over using average weather data.

As shown by the regression results in Appendix B, in the case of retail model, statistical significance of the weather variable based on using Toronto data in terms of t Statistics is better compared to its counterpart using average weather data. Overall, t statistics are larger for 8 estimated coefficients and smaller for only one. We can conclude that the model using Toronto weather data overwhelmingly outperforms the model based on average weather data. In the case of embedded LDC model, regardless of type of weather data used, the weather variable is statistically insignificant at any reasonable probability level. Its inclusion was motivated by the fact that there is some weather-sensitive load in these utilities although it is statistically insignificant. Overall, the number of estimates based on Toronto weather with a higher t-ratio compared to their counterpart using average weather data is the same as those having lower t-ratios so that the results are inconclusive. However, given the overwhelming results in support of using Toronto weather data in the retail equation as well as in the transmission related equations, we may conclude that Toronto weather data outperforms the average weather data for the aggregate models discussed above. For disaggregated models at customer delivery points, as noted in part 3.4, Hydro One uses local weather stations closest to each delivery point, as in previous Distribution rate filings (RP-2005-0020/EB-2005-0378, EB-2007-0681, EB-2009-0096, EB-2013-0416, and EB-2017-0049).

<u>End-Use Model</u>

The end-use models cover the residential (year round and seasonal), commercial, industrial and agricultural sectors. Detailed equations of the end-use models are provided in Appendix C.

The above models are used to prepare forecast 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 residential
- Acquired general service – energy billed
- Acquired general service – demand billed
- Acquired urban residential
- Acquired urban general service – energy billed
- Acquired urban general service – demand billed

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 2021, 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 utility customers, an annual econometric model is used to prepare the load forecast as a group. The model used 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 provided in the economic forecast.

The econometric approach was used to forecast the load for embedded utilities and industrial analysis was used to forecast the load for the embedded industrial customers. In both cases, results from the customer survey were 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 customer class and for specific customer delivery points.

Hourly Load Shape by Rate Class

The Electricity Power Research Institute (EPRI)'s Hourly Electric Load Model (HELM) was used to develop the hourly load shape for each rate class, taking out abnormal weather effects and load patterns. Actual 2019 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 hourly load shapes. For rate classes that hourly data was not available for all customers, the hourly data was scaled to add up to the actual load for that rate class. Similarly, the hourly forecast for each rate class 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 2021-2027 take into account reclassification of some customers between rate classes in accordance with the annual forecast. In particular, the seasonal class is assumed to be eliminated in 2023, with all seasonal customers having been moved to appropriate year-round residential classes. Appendix D provides more details for the methodology used by Hydro One to weather-normalize the total utility load and for each rate class.

Hourly Load Shape by Customer Delivery Point

Similarly, the HELM is used to normalize the hourly load for each of the customer delivery points, taking out abnormal weather effects and load patterns. The customer forecast is used to drive the customer delivery point forecast. Key information used in the analysis includes hourly load and weather data.

The most up to date customer totalization table[1] is used to retrieve hourly electricity demand data for each of the customer delivery points connected to the Sub Transmission (ST) system. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. Hourly weather data is also retrieved to prepare weather sensitivity analysis. Weather data analyzed includes temperature, wind speed, cloud cover and humidity. Each delivery point is linked

[1] The totalization table provides the latest records of Hydro One Distribution delivery points.

to the data from the closest weather station (i.e. Toronto, Windsor, Ottawa, North Bay and Thunder Bay).

In preparing the database for the load shape analysis, missing values are estimated by load on a similar day and hour during the same month. For weather-sensitive load, weather conditions are also taken into account in estimating the missing values. To perform the latter task, an hourly regression model (relating load to weather conditions) for each delivery point with missing values was developed.

EPRI's HELM is used to prepare the hourly weather response analysis for each delivery point. The model takes into account differences in load depending upon time of use (i.e. 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 hour during the historical period.

4.0 LOAD FORECAST FOR 2021-2027

Hydro One's distribution system delivered a total of 35,001 GWh in 2019 and 34,673 GWh in 2020 on a weather-normal basis. Table 5 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 38,466 GWh in 2021. Load before deducting the CDM impacts over the years 2022 to 2027 is expected to continue to grow with the load forecast reaching 38,828, 40,196, 40,405, 40,562, 40,688, 41,093 GWh, respectively, on a weather-normal basis. The forecast reflects the continuation of economic recovery from the pandemic as well as the impact of integrating the Acquired Utilities into Hydro One Distribution in 2023.

Hydro One Distribution served about 1,314,000 customers in 2019 and 1,323,000 customers in 2020. Hydro One Distribution is forecast to serve about 1,333,000 customers in 2021. The customer numbers are forecast to be 1,343,000, 1,414,000, 1,424,000; 1,434,000, 1,444,000, and 1,453,000 respectively over the 2022 to 2027 period. The figures for 2023 to 2027 include the impact of integrating the Acquired Utilities into Hydro One Distribution in 2023.

After applying the impact of CDM, Hydro One Distribution's load declines from 35,001 GWh in 2019 to 34,673 GWh in 2020, largely due to the pandemic, and is forecast to increase to 34,785 GWh in 2021, on a weather-normalized basis. Over the years 2022 to 2027, the weather-normalized total distribution load is forecast to be 34,907, 35,854, 35,974, 36,090, 36,202, and 36,312 GWh, respectively. Detailed tables for actual and weather-normalized total load, energy and peak by rate class are provided in Appendix E, Tables E.5 to E.7. The peak forecast for each rate class is derived from corresponding sales forecast using load factor. Results by rate class in Appendix E reflect changes due to customer classification (see Exhibit G-01-02-01 of Hydro One's distribution application EB-2013-0416) and continuation of these changes over the years 2021 to 2027 as discussed in Exhibit L-01-02 of the current Application.

Table 5 - 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			
2019	21,360	17,085	38,445
2020	21,323	16,806	38,128
2021	21,519	16,947	38,466
2022	21,730	17,099	38,828
2023 *	23,123	17,073	40,196
2024 *	23,240	17,166	40,405
2025*	23,327	17,235	40,562
2026*	23,396	17,292	40,688
2027*	23,644	17,449	41,093
Load Impact of CDM			
2019	2,154	1,290	3,444
2020	2,174	1,282	3,456
2021	2,315	1,366	3,681
2022	2,466	1,456	3,922
2023 *	2,777	1,565	4,343
2024 *	2,833	1,598	4,431
2025*	2,859	1,613	4,472
2026*	2,867	1,619	4,486
2027*	3,055	1,726	4,781
Load Forecast After Deducting Impact of CDM			
2019	19,207	15,794	35,001
2020	19,149	15,524	34,673
2021	19,204	15,581	34,785
2022	19,264	15,643	34,907
2023 *	20,346	15,508	35,854
2024 *	20,406	15,568	35,974
2025*	20,468	15,622	36,090
2026*	20,529	15,673	36,202
2027*	20,589	15,723	36,312

Note. All figures are weather-normal.
* Includes Acquired Utilities.

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 growth pattern. Table 6 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 (2021-2027) 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 6 - One Standard Deviation Uncertainty Bands for Hydro One Distribution Load (GWh)

Year	Lower Bound	Forecast	Upper Bound
2020	34,673	34,673	34,673
2021	34,100	34,785	35,459
2022	34,033	34,907	35,787
2023	34,820	35,854	36,889
2024	34,683	35,974	37,260
2025	34,558	36,090	37,649
2026	34,347	36,202	38,090
2027	34,075	36,312	38,588

Note. 2020 figures are actuals

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 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 1997 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 E

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 E

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).

Seasonal Factors	State-Space (SS) parameters:
A[1]	-0.223049
K[1]	-0.40248
Non-Seasonal Factors	SS parameters:
A[1]	0.269131
K[1]	-0.550363
GDPONT[-4]	0.174041
BPONT[-8]	0.00644967
D98JAN	-0.0194215

R-squared = 0.979, R-squared corrected for mean = 0.979, Durbin-Watson Statistics = 2.02.

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 for the variations in load. 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.

APPENDIX B

ANNUAL ECONOMETRIC MODELS

In this Appendix, regression results for annual econometric models are presented. As explained in the main text, in each case, two sets of results are provided; one base on Toronto weather data and the other on average weather data for 5 weather stations across Ontario (Thunder Bay, Windsor, Toronto, Ottawa, and North Bay). The results are discussed in Section 2.2.

<u>Retail Load</u>

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+C(6)*D99A+C(7)*TR
+C(8)*TR2+C(9)*D08ON

where:

LRTLT = logarithm of retail load,

LYPDPHH = logarithm of Ontario personal disposable income per household / house 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 IHS Global Insight housing starts
- Forecast is based on forecasts of disposable income from C4SE and Conference Board of Canada deflated by CPI from IHS Global Insight and divided by the number of household / houses based on consensus forecast of housing starts as presented in Exhibit E-03-01 Appendix A

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and Canada Energy Regulator (CER) 2020
- Forecast is from CER 2020 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, IHS GI, 2013 LTEP and CER 2020 Outlook
- Forecast is from CER 2020 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,

TR2 = TR to power 2,

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

C(1) – C(9) = variable coefficients.

The estimated model using Toronto weather data are presented below:

	Estimated Coefficient	Standard Error	t-ratio	Prob.
C(1)	3.563196	1.194592	2.982771	0.0053
C(2)	0.620628	0.090365	6.867987	0
C(3)	-0.016304	0.009794	-1.664657	0.1054
C(4)	0.093664	0.037246	2.514717	0.017
C(5)	0.405997	0.114543	3.544488	0.0012
C(6)	-0.037431	0.00849	-4.408812	0.0001
C(7)	-0.074783	0.02762	-2.707553	0.0107
C(8)	0.001921	0.00062	3.098526	0.004
C(9)	-0.035805	0.010079	-3.552438	0.0012

R-squared = 0.989, Adjusted R-squared = 0.986, Durbin-Watson Statistic = 2.10.

Similar to 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. 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.

With the estimated model using average degree days for the l five weather stations, we have

	Estimated Coefficient	Standard Error	t-ratio	Prob.
C(1)	3.814613	1.249989	3.051718	0.0045
C(2)	0.6167	0.093471	6.597784	0
C(3)	-0.016071	0.010091	-1.592561	0.1208
C(4)	0.082904	0.041089	2.017657	0.0518
C(5)	0.38704	0.11912	3.249148	0.0027
C(6)	-0.037936	0.008753	-4.334054	0.0001
C(7)	-0.076695	0.028615	-2.680253	0.0114
C(8)	0.00197	0.000642	3.067575	0.0043
C(9)	-0.035069	0.010353	-3.387236	0.0018

R-squared = 0.988, Adjusted R-squared = 0.985, Durbin-Watson Statistic = 2.17.

<u>Embedded LDC Load</u>

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)*LEMBLDCS(-1)-C(4)*C(5)*LCDD(-1)+C(7)/TR

where:

LEMBLDCS = logarithm of Embedded LDC load,

LHHOLD = logarithm of Ontario number of households / houses,

- History from IHS Global Insight housing starts
- Forecast is based on consensus forecast of housing starts as presented in Exhibit E-03-01 Appendix A

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (CER) 2020 Outlook
- Forecast is from CER 2020 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, IHS GI, 2013 LTEP and CER 2020
- Forecast is from CER 2020 Outlook accounting for carbon tax

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

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,

C(1) – C(7) = variable coefficients.

The estimated model based on Toronto weather data are presented below:

	Estimated Coefficient	Standard Error	t-ratio	Prob.
C(1)	1.867618	0.677821	2.755326	0.0091
C(2)	1.779738	0.915805	1.94336	0.0598
C(3)	-0.043179	0.016524	-2.61307	0.013
C(4)	0.010377	0.009297	1.11618	0.2717
C(5)	0.823102	0.063279	13.00756	0
C(6)	-4.99829	2.133486	-2.34278	0.0248

R-squared = 0.973, Adjusted R-squared = 0.970, Durbin-Watson Statistic = 2.02.

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

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.

For the estimated model using average degree days for the five weather stations we have:

	Estimated Coefficient	Standard Error	t-ratio	Prob.
C(1)	1.830879	0.679832	2.693134	0.0107
C(2)	1.838086	0.922163	1.993233	0.0539
C(3)	-0.042578	0.016546	-2.573337	0.0143
C(4)	0.011339	0.010002	1.133716	0.2644
C(5)	0.826524	0.063413	13.03388	0
C(6)	-4.926577	2.140599	-2.301495	0.0273

R-squared = 0.973, Adjusted R-squared = 0.970, Durbin-Watson Statistic = 2.01.

APPENDIX C

END-USE MODEL

The following briefly describes the methodology used in the end-use model.

Residential Sector

The residential energy forecast is determined by forecasting the number of accounts times appliance saturation rates and unit energy consumption expressed in the following equation:

$$USE_{\mathrm{Res}} = \sum_i \sum_j N_{i,j} * S_{i,j} * UEC_{i,j}$$

Where

- USE_{Res} is residential energy consumption
- N is the number of residential accounts
- S is the residential appliance saturation rate
- UEC is the unit energy consumption per end use
- I is the index for appliances (space heating, space cooling, water heater and base load)
- J is the index for customer types—year-round residential customers and seasonal residential customers

The following section describes each component of the equation in detail.

- The base-year number of households is taken from Hydro One Distribution billing system. The forecast in the growth of the number of residential accounts is based on a forecast of housing starts. The number of residential accounts is the current number of residential accounts plus the forecast of net additional accounts to be added each year.
- The base-year end-use shares (space heating, water heating and air conditioning) information is based on the latest customer and conservation survey results undertaken by Hydro One for year-round and seasonal customers.

- The base-year end-use UEC's are based on the provincial residential end-use model with adjustments for heating degree-days, cooling degree-days, income, household size, square footage and household vintage.

Commercial Sector

The commercial energy forecast is based on the following equation:

$USEcom = USEcom$ (-1) * (1+Expected annual growth rate)

Where

- $USEcom$ is the commercial energy consumption for the forecast year
- $USEcom$ (-1) is the commercial energy consumption for the previous year. The base year consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on commercial GDP growth by segment. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.

Industrial Sector

The industrial energy forecast is based on the following equation:

$$USEind = USEind\,(-1) * (1+\text{Expected annual growth rate})$$

Where

- $USEind$ is the industrial energy consumption for the forecast year
- $USEind$ (-1) is the industrial energy consumption for the previous year. The base year consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on industrial GDP growth by segment. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.

Agricultural Sector

The Agricultural sector forecast is based on the following equation:

$$USEagri = USEagri\,(-1) * (1+\text{Expected annual growth rate})$$

Where

- $USEagri$ is the agricultural energy consumption for the forecast year
- $USEagri$ (-1) is the agricultural energy consumption for the previous year. The base year consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on the GDP growth for agriculture and forestry. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.

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 and 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 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 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 C., 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 (2007 M$)	% change	Population (1,000's)	% change	Housing (1,000's)	% change
2010	656,103	3.0	13,136	1.1	61.0	22.6
2011	671,942	2.4	13,261	1.0	67.8	11.1
2012	680,792	1.3	13,391	1.0	77.4	14.1
2013	690,275	1.4	13,511	0.9	61.1	-21.1
2014	707,589	2.5	13,618	0.8	58.6	-4.1
2015	724,946	2.5	13,707	0.7	69.0	17.8
2016	740,164	2.1	13,875	1.2	74.7	8.3
2017	761,025	2.8	14,070	1.4	79.9	6.9
2018	782,115	2.8	14,309	1.7	79.1	-1.0
2019	798,213	2.1	14,545	1.6	69.0	-12.8
2020	751,945	-5.8	14,734	1.3	77.6	12.5
2021	785,657	4.5	14,919	1.3	75.2	-3.1
2022	818,719	4.2	15,110	1.3	76.5	1.7
2023	836,554	2.2	15,292	1.2	77.0	0.6
2024	853,468	2.0	15,460	1.1	76.9	-0.1
2025	871,379	2.1	15,616	1.0	75.3	-2.0
2026	888,678	2.0	15,770	1.0	69.9	-7.2
2027	905,308	1.9	15,917	0.9	69.6	-0.4

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	Weather Corrected Actual	Actual	% Difference from Weather Corrected Actual 2005 Forecast	2007 Forecast	2009 Forecast	2013 Forecast	2018 * 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
Average								0.29	0.83	-0.39	2.68	-0.26

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

Table E.3 - Number of Customers History and Forecast

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generator	893	907	1,004	1,064	1,131	1,220	1,316	1,403	1,489	1,576	1,662	1,748	1,834
General Service - Demand Billed	6,098	5,323	5,231	5,334	5,411	5,348	5,367	5,420	5,343	5,393	5,439	5,487	5,536
General Service - Energy Billed	87,686	88,878	88,523	88,069	88,774	88,904	88,236	88,547	88,795	88,831	88,891	88,970	89,067
Residential - Medium Density	432,519	441,836	447,647	452,784	460,401	467,744	471,502	476,358	544,981	549,783	554,504	558,944	563,326
Residential - Low Density	328,170	328,766	330,514	328,694	331,131	332,341	331,534	333,713	414,577	416,658	418,668	420,454	422,190
Seasonal	153,498	148,991	147,253	145,764	144,528	143,125	142,976	142,813	0	0	0	0	0
Sub-transmission *	838	804	805	817	828	877	879	881	910	917	924	931	938
Urban General Service - Demand Billed	1,893	1,715	1,711	1,731	1,758	1,732	1,753	1,773	1,743	1,753	1,764	1,775	1,786
Urban General Service - Energy Billed	17,703	17,780	17,747	18,020	17,858	17,832	18,678	18,435	18,432	18,524	18,620	18,720	18,824
Urban Residential	208,639	213,199	215,844	228,062	230,439	233,214	240,193	243,175	246,399	249,390	252,344	255,172	257,972
Street Light *	5,118	5,251	5,428	5,322	5,515	5,362	5,404	5,445	5,494	5,536	5,577	5,615	5,654
Sentinel Light *	25,689	24,364	22,761	21,936	21,189	20,218	19,886	19,558	19,409	19,086	18,765	18,439	18,117
Unmetered Scattered Load *	5,624	5,537	5,455	5,494	5,500	5,504	5,547	5,589	5,752	5,793	5,832	5,869	5,906
Acquired Residential	36,382	36,487	36,664	37,698	38,164	38,372	38,577	38,783	38,991	39,198	39,401	39,591	39,777
Acquired General Service - Energy Billed	4,350	4,348	4,282	4,268	4,282	4,168	4,240	4,233	4,223	4,213	4,203	4,193	4,183
Acquired General Service - Demand Billed	330	336	292	281	277	293	297	301	303	306	308	311	313
Acquired Urban Residential	14,353	14,515	14,703	14,949	15,182	15,256	15,329	15,402	15,476	15,550	15,622	15,690	15,756
Acquired Urban General Service - Energy Billed	1,246	1,263	1,257	1,278	1,278	1,319	1,344	1,368	1,380	1,392	1,404	1,416	1,427
Acquired Urban General Service - Demand Billed	193	193	201	180	189	213	213	213	207	207	208	208	208
Sum: Includes Newly Acquired for 2023-2027 only	1,274,369	1,283,351	1,289,922	1,303,089	1,314,463	1,323,421	1,333,269	1,343,110	1,413,905	1,424,106	1,434,135	1,443,532	1,452,813

* Includes Acquired Utilities corresponding figures in 2023 and 2027 only.

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

Year	Actual/Forecast GWh	% Change	Normalized Weather GWh	% Change
2015	36,686	-2.9	36,419	-1.8
2016	35,856	-2.3	36,139	-0.8
2017	35,101	-2.1	35,426	-2.0
2018	35,846	2.1	34,023	-4.0
2019	36,738	2.5	35,001	2.9
2020	37,029	0.8	34,673	-0.9
2021	34,785	-6.1	34,785	0.3
2022	34,907	0.4	34,907	0.4
2023*	35,854	2.7	35,854	2.7
2024*	35,974	0.3	35,974	0.3
2025*	36,090	0.3	36,090	0.3
2026*	36,202	0.3	36,202	0.3
2027*	36,312	0.3	36,312	0.3

* Includes Acquired Utilities.

Table E.5 - Actual Sales and Forecast in GWh

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generator	16	17	26	29	29	28	29	30	31	31	32	33	34
General Service - Demand Billed	2,394	2,343	2,482	2,542	2,447	2,364	2,197	2,201	2,201	2,205	2,208	2,212	2,215
General Service - Energy Billed	2,189	2,132	2,239	2,322	2,329	2,222	2,049	2,039	2,011	2,000	1,989	1,978	1,967
Residential - Medium Density	4,930	4,851	4,596	4,927	4,954	5,101	4,770	4,813	5,124	5,167	5,210	5,253	5,296
Residential - Low Density	4,767	4,614	4,418	4,783	4,832	4,902	4,537	4,537	4,867	4,867	4,866	4,866	4,865
Seasonal	671	641	594	711	647	698	641	637	0	0	0	0	0
Sub-transmission *	15,806	15,468	15,143	15,915	15,728	15,618	15,068	15,128	14,998	15,056	15,108	15,158	15,206
Urban General Service - Demand Billed	1,064	1,036	1,020	1,059	1,007	934	883	885	891	893	896	898	900
Urban General Service - Energy Billed	600	589	597	616	602	567	534	535	552	552	552	552	553
Urban Residential	1,983	1,947	1,833	1,994	1,946	2,100	1,966	1,988	2,041	2,063	2,086	2,108	2,130
Street Light *	122	122	100	89	84	79	79	79	84	84	83	83	83
Sentinel Light *	21	21	14	14	13	12	12	11	11	11	11	11	11
Unmetered Scattered Load *	24	24	29	29	30	31	31	31	33	33	33	34	34
Acquired Residential	301	300	297	342	328	348	330	338	336	334	332	330	327
Acquired General Service - Energy Billed	110	109	111	120	117	119	115	118	117	116	115	114	113
Acquired General Service - Demand Billed	235	237	267	271	242	238	229	233	231	229	227	225	223
Acquired Urban Residential	102	100	100	112	117	123	116	117	118	119	119	120	121
Acquired Urban General Service - Energy Billed	43	43	41	45	49	43	40	41	41	41	42	42	43
Acquired Urban General Service - Demand Billed	136	138	161	197	196	186	178	183	118	119	119	119	119
Sum: Includes Acquired Utilities for 2023-2027 only	34,586	33,804	33,093	35,028	34,647	34,656	32,797	32,912	33,807	33,921	34,030	34,136	34,239

* Includes Acquired Utilities corresponding figures in 2023 and 2027 only.

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

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generator	16	17	26	29	29	28	29	30	31	31	32	33	34
General Service - Demand Billed	2,373	2,368	2,515	2,407	2,260	2,194	2,197	2,201	2,201	2,205	2,208	2,212	2,215
General Service - Energy Billed	2,169	2,155	2,269	2,198	2,152	2,063	2,049	2,039	2,011	2,000	1,989	1,978	1,967
Residential - Medium Density	4,901	4,907	4,645	4,766	4,746	4,725	4,770	4,813	5,124	5,167	5,210	5,253	5,296
Residential - Low Density	4,738	4,668	4,464	4,627	4,629	4,541	4,537	4,537	4,867	4,867	4,866	4,866	4,865
Seasonal	667	648	600	687	620	647	641	637	0	0	0	0	0
Sub-transmission *	15,683	15,526	15,243	15,275	15,137	15,013	15,068	15,128	14,998	15,056	15,108	15,158	15,206
Urban General Service - Demand Billed	1,054	1,047	1,034	1,001	905	881	883	885	891	893	896	898	900
Urban General Service - Energy Billed	595	595	605	582	541	534	534	535	552	552	552	552	553
Urban Residential	1,971	1,969	1,852	1,948	1,867	1,943	1,966	1,988	2,041	2,063	2,086	2,108	2,130
Street Light *	122	122	100	89	84	79	79	79	84	84	83	83	83
Sentinel Light *	21	21	14	14	13	12	12	11	11	11	11	11	11
Unmetered Scattered Load *	24	24	29	29	30	31	31	31	33	33	33	34	34
Acquired Residential	299	300	300	333	315	322	330	338	336	334	332	330	327
Acquired General Service - Energy Billed	109	109	112	113	107	112	115	118	117	116	115	114	113
Acquired General Service - Demand Billed	233	237	270	256	220	223	229	233	231	229	227	225	223
Acquired Urban Residential	101	100	101	110	113	114	116	117	118	119	119	120	121
Acquired Urban General Service - Energy Billed	42	43	42	43	44	40	40	41	41	41	42	42	43
Acquired Urban General Service - Demand Billed	135	138	164	186	176	174	178	183	118	119	119	119	119
Sum: Includes Acquired Utilities for 2023-2027 only	34,334	34,068	33,397	33,650	33,013	32,691	32,797	32,912	33,807	33,921	34,030	34,136	34,239

* Includes Acquired Utilities corresponding figures in 2023 to 2027 only.

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

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2015	165,405	8,536,187	3,076,837	35,473,518	662,107	393,100	47,251,947
2016	171,973	8,118,010	2,846,792	33,699,203	665,454	397,953	44,835,978
2017	188,672	7,848,256	2,745,769	30,285,554	663,744	403,987	41,068,251
2018	196,614	7,528,602	2,640,406	28,829,784	627,455	577,262	39,195,406
2019	198,346	7,639,374	2,666,577	26,468,846	672,176	546,176	36,973,143
2020	192,801	7,248,717	2,457,504	31,360,107	666,224	525,155	41,259,129
2021	199,269	7,042,734	2,313,437	30,741,357	638,623	502,596	40,296,797
2022	205,708	7,053,913	2,314,342	30,863,778	651,472	514,709	40,437,740
2023	212,159	7,055,234	2,323,294	30,658,244	646,691	334,039	41,229,661
2024	218,623	7,066,511	2,324,116	30,776,974	640,641	334,225	41,361,090
2025	225,100	7,077,802	2,324,938	30,883,978	635,376	334,687	41,481,883
2026	231,590	7,089,109	2,325,762	30,984,500	629,258	334,742	41,594,960
2027	238,092	7,100,430	2,326,587	31,082,807	622,315	334,386	41,704,616

* The total and ST include corresponding Acquired Utilities figures and for only 2023 to 2027.

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

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2015	165,405	8,484,670	3,058,267	35,259,430	658,111	390,728	46,967,772
2016	171,973	8,116,669	2,846,321	33,693,637	665,344	397,887	44,828,600
2017	191,621	7,970,925	2,788,685	30,758,917	674,118	410,301	41,710,148
2018	196,614	7,531,163	2,641,235	28,839,440	627,668	577,443	39,208,452
2019	198,346	7,432,859	2,600,591	30,918,505	654,005	532,660	41,150,301
2020	192,801	7,033,288	2,313,812	30,629,379	623,758	489,352	40,169,280
2021	199,269	7,042,734	2,313,437	30,741,357	638,623	502,596	40,296,797
2022	205,708	7,053,913	2,314,342	30,863,778	651,472	514,709	40,437,740
2023	212,159	7,055,234	2,323,294	30,658,244	646,691	334,039	41,229,661
2024	218,623	7,066,511	2,324,116	30,776,974	640,641	334,225	41,361,090
2025	225,100	7,077,802	2,324,938	30,883,978	635,376	334,687	41,481,883
2026	231,590	7,089,109	2,325,762	30,984,500	629,258	334,742	41,594,960
2026	238,092	7,100,430	2,326,587	31,082,807	622,315	334,386	41,704,616

* The total and ST include corresponding Acquired Utilities figures and for only 2023 to 2027.

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

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
General Service - Demand Billed	295	328	368	397	392	388	415	443	471	482	487	490	524
General Service - Energy Billed	374	418	462	501	505	514	545	578	611	620	623	622	660
Residential - Medium Density	239	270	294	323	323	327	349	372	416	424	428	430	458
Residential - Low Density	231	257	283	304	303	305	324	344	391	398	400	400	425
Seasonal	32	36	38	41	41	41	43	46	0	0	0	0	0
Sub-transmission *	630	752	810	997	1,067	1,145	1,189	1,415	1,308	1,300	1,368	1,439	1,528
Urban General Service - Demand Billed	131	145	151	168	162	162	173	185	197	201	204	205	220
Urban General Service - Energy Billed	102	115	123	137	134	138	147	157	167	170	172	173	185
Urban Residential	96	108	117	134	136	139	149	160	171	176	179	181	194
Acquired Residential	25	27	28	29	28	29	31	32	34	35	35	35	38
Acquired General Service - Energy Billed	14	16	18	20	29	29	31	32	34	34	35	35	37
Acquired General Service - Demand Billed	30	34	37	42	34	34	36	39	41	42	43	43	46
Acquired Urban Residential	15	16	17	17	17	17	18	19	20	21	21	21	22
Acquired Urban General Service - Energy Billed	6	7	7	8	12	12	13	13	14	15	15	15	16
Acquired Urban General Service - Demand Billed	20	22	25	28	25	25	27	29	30	31	31	31	34
Sum: Includes Acquired Utilities for 2023-2027 only	2,130	2,430	2,647	3,002	3,063	3,160	3,335	3,700	3,905	3,949	4,041	4,119	4,385

* Includes Acquired Utilities corresponding figures in 2023 and 2027 only.

**Note: All savings are at end-use level*

DATA FOR HYDRO ONE DISTRIBUTION LOAD FORECAST

This exhibit has been filed separately in MS Excel format.

Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells:				
		Data input		Drop-down List
		No data entry required		Blank or calculated value

Distribution System (Total)

*Note: Customer and connections data is mid-year data

	Calendar Year (for 2023 Cost of Service		Consumption (kWh) (3) Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actua	33,092,716,729	33,396,564,855		
Historical	2018	Actua	35,027,859,480	33,649,614,077	OEB-approved	33,050,624,446
Historical	2019	Actua	34,646,837,468	33,012,995,876		
Historical	2020	Actua	34,656,344,601	32,690,887,255		
Historical	2021	Actua	32,797,009,933	32,797,009,933		
Bridge Year	2022	Forecast		32,912,296,764		
Test Year	2023	Forecast		33,093,024,662		

Variance Analysis	Year	Year-over-year		Versus OEB-approved
	2017			
	2018	5.8%	0.8%	
	2019	-1.1%	-1.9%	
	2020	0.0%	-1.0%	
	2021	-5.4%	0.3%	
	2022		0.4%	
	2023		0.5%	0.1%
	Geometric Mean	-0.3%	-0.2%	0.0%

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

1 Customer Class: R1 — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service	Customers			
Historical	2017	Actual	447,647		
Historical	2018	Actual	452,784	OEB-approved	447,465
Historical	2019	Actual	460,401		
Historical	2020	Actual	467,744		
Historical	2021	Actual	471,502		
Bridge Year	2022	Forecast	476,358		
Test Year	2023	Forecast	544,981		

	Calendar Year (for 2023 Cost of Service		Consumption (kWh) (3) Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	4,596,271,466	4,644,516,543		
Historical	2018	Actual	4,926,943,405	4,765,931,078	OEB-approved	4,591,766,176
Historical	2019	Actual	4,953,924,255	4,746,079,199		
Historical	2020	Actual	5,101,350,354	4,725,019,159		
Historical	2021	Actual	4,770,188,009	4,770,188,009		
Bridge Year	2022	Forecast		4,812,665,028		
Test Year	2023	Forecast		5,124,449,212		

	Calendar Year (for 2023 Cost of Service		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	10,267.62	10,375.40		
Historical	2018	Actual	10,881.44	10,525.84	OEB-approved	10,261.74
Historical	2019	Actual	10,760.02	10,308.58		
Historical	2020	Actual	10,906.29	10,101.72		
Historical	2021	Actual	10,117.01	10,117.01		
Bridge Year	2022	Forecast	0.00	10,103.05		
Test Year	2023	Forecast	0.00	9,402.99		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved
	2017		
	2018	1.1%	
	2019	1.7%	
	2020	1.6%	
	2021	0.8%	
	2022	1.0%	
	2023	14.4%	21.8%
	Geometric Mean	4.0%	5.1%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	7.2%	2.6%	
2019	0.5%	-0.4%	
2020	3.0%	-0.4%	
2021	-6.5%	1.0%	
2022		0.9%	
2023		6.5%	11.6%
Geometric Mean	1.2%	2.0%	2.8%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	6.0%	1.4%	
2019	-1.1%	-2.1%	
2020	1.4%	-2.0%	
2021	-7.2%	0.2%	
2022		-0.1%	
2023		-6.9%	-8.4%
Geometric Mean	-0.5%	-1.9%	-2.2%

	Calendar Year (for 2023 Cost of Service	Revenues		
Historical	2017	Actual	$ 287,118,714	
Historical	2018	Actual	$ 296,805,886	OEB-approved
Historical	2019	Actual	$ 319,461,424	
Historical	2020	Actual	$ 351,533,042	
Historical	2021	Actual	$ 348,972,650	
Bridge Year (Forecast)	2022	Forecast	$ 373,588,314	
Test Year (Forecast)	2023	Forecast	$ 405,561,433	

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved
	2017		
	2018	3.4%	
	2019	7.6%	
	2020	10.0%	
	2021	-0.7%	
	2022	7.1%	
	2023	8.6%	
	Geometric Mean	7.2%	

2 **Customer Class:** R2

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	330,514		
Historical	2018	Actual	328,694	OEB-approved	328,479
Historical	2019	Actual	331,131		
Historical	2020	Actual	332,341		
Historical	2021	Actual	331,534		
Bridge Year	2022	Forecast	333,713		
Test Year	2023	Forecast	414,577		

Year		Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	4,418,065,636	4,464,440,163		
2018	Actual	4,783,005,056	4,626,696,629	OEB-approved	4,330,539,160
2019	Actual	4,832,033,176	4,629,302,138		
2020	Actual	4,902,422,490	4,540,766,382		
2021	Actual	4,537,299,687	4,537,299,687		
2022	Forecast		4,536,851,904		
2023	Forecast		4,867,286,071		

Year		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	13,367.28	13,507.59		
2018	Actual	14,551.57	14,076.02	OEB-approved	13,183.61
2019	Actual	14,592.51	13,980.27		
2020	Actual	14,751.18	13,662.97		
2021	Actual	13,685.78	13,685.78		
2022	Forecast	0.00	13,595.08		
2023	Forecast	0.00	11,740.37		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus OEB-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017								
2018	-0.6%		8.3%	3.6%		8.9%	4.2%	
2019	0.7%		1.0%	0.1%		0.3%	-0.7%	
2020	0.4%		1.5%	-1.9%		1.1%	-2.3%	
2021	-0.2%		-7.4%	-0.1%		-7.2%	0.2%	
2022	0.7%			0.0%			-0.7%	
2023	24.2%	26.2%		7.3%	12.4%		-13.6%	-10.9%
Geometric Mean	4.6%	6.0%	0.9%	1.7%	3.0%	0.8%	-2.8%	-2.9%

	Calendar Year (for 2023 Cost of Service)		Revenues	
Historical	2017	Actual	$ 483,837,448	
Historical	2018	Actual	$ 495,731,775	OEB-approved
Historical	2019	Actual	$ 530,055,367	
Historical	2020	Actual	$ 573,964,846	
Historical	2021	Actual	$ 563,576,722	
Bridge Year (Forecast)	2022	Forecast	$ 598,934,936	
Test Year (Forecast)	2023	Forecast	$ 629,351,204	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	2.5%	
2019	6.9%	
2020	8.3%	
2021	-1.8%	
2022	6.3%	
2023	5.1%	
Geometric Mean	5.4%	

3 **Customer Class:** Seasonal

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	147,253		
Historical	2018	Actual	145,764	OEB-approved	147,679
Historical	2019	Actual	144,528		
Historical	2020	Actual	143,125		
Historical	2021	Actual	142,976		
Bridge Year	2022	Forecast	142,813		
Test Year	2023	Forecast	-		

Year		Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	594,045,826	600,281,268		
2018	Actual	710,528,483	687,308,439	OEB-approved	585,362,231
2019	Actual	646,765,018	619,629,578		
2020	Actual	698,466,212	646,939,733		
2021	Actual	641,349,378	641,349,378		
2022	Forecast		636,543,319		
2023	Forecast		0		

Year		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	4,034.20	4,076.54		
2018	Actual	4,874.53	4,715.23	OEB-approved	3,963.75
2019	Actual	4,475.02	4,287.26		
2020	Actual	4,880.11	4,520.10		
2021	Actual	4,485.71	4,485.71		
2022	Forecast	0.00	4,457.17		
2023	Forecast				

Variance Analysis

Year	Customers Year-over-year	Test Year Versus OEB-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017								
2018	-1.0%		19.6%	14.5%		20.8%	15.7%	
2019	-0.8%		-9.0%	-9.8%		-8.2%	-9.1%	
2020	-1.0%		8.0%	4.4%		9.1%	5.4%	
2021	-0.1%		-8.2%	-0.9%		-8.1%	-0.8%	
2022	-0.1%			-0.7%			-0.6%	
2023	-100.0%	-100.0%		-100.0%	-100.0%		Not Applicable	Not Applicable
Geometric Mean	-100.0%	-100.0%	2.6%	-100.0%	-100.0%	3.6%	Not Applicable	Not Applicable

	Calendar Year (for 2023 Cost of Service)		Revenues	
Historical	2017	Actual	$ 101,829,758	
Historical	2018	Actual	$ 108,578,156	OEB-approved
Historical	2019	Actual	$ 110,801,098	
Historical	2020	Actual	$ 121,601,144	
Historical	2021	Actual	$ 116,779,993	
Bridge Year (Forecast)	2022	Forecast	$ 121,728,453	
Test Year (Forecast)	2023	Forecast	Not Applicable	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	6.6%	
2019	2.0%	
2020	9.7%	
2021	-4.0%	
2022	4.2%	
2023	Not Applicable	
Geometric Mean	4.6%	

4 **Customer Class:** Urban Residential

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	215,844		
Historical	2018	Actual	228,062	OEB-approved	227,025
Historical	2019	Actual	230,439		
Historical	2020	Actual	233,214		
Historical	2021	Actual	240,193		
Bridge Year	2022	Forecast	243,175		
Test Year	2023	Forecast	246,399		

	Calendar Year	Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	1,832,808,736	1,852,046,938		
Historical	2018	Actual	1,994,251,700	1,947,562,277	OEB-approved	1,909,812,707
Historical	2019	Actual	1,945,901,295	1,866,970,307		
Historical	2020	Actual	2,100,222,530	1,943,063,879		
Historical	2021	Actual	1,965,638,409	1,965,638,409		
Bridge Year	2022	Forecast		1,987,567,726		
Test Year	2023	Forecast		2,041,267,573		

	Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	8,491.36	8,580.49		
Historical	2018	Actual	8,744.34	8,539.62	OEB-approved	8,412.33
Historical	2019	Actual	8,444.32	8,101.80		
Historical	2020	Actual	9,005.56	8,331.68		
Historical	2021	Actual	8,183.59	8,183.59		
Bridge Year	2022	Forecast	0.00	8,173.40		
Test Year	2023	Forecast	0.00	8,284.38		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus OEB-approved	Year	Consumption Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Year	Per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017			2017				2017			
2018	5.7%		2018	8.8%	5.2%		2018	3.0%	-0.5%	
2019	1.0%		2019	-2.4%	-4.1%		2019	-3.4%	-5.1%	
2020	1.2%		2020	7.9%	4.1%		2020	6.6%	2.8%	
2021	3.0%		2021	-6.4%	1.2%		2021	-9.1%	-1.8%	
2022	1.2%		2022		1.1%		2022		-0.1%	
2023	1.3%	8.5%	2023		2.7%	6.9%	2023		1.4%	-1.5%
Geometric Mean	2.7%	2.1%	Geometric Mean	2.4%	2.0%	1.7%	Geometric Mean	-1.2%	-0.7%	-0.4%

	Calendar Year (for 2023 Cost of Service)	Revenues		
Historical	2017	Actual	$ 81,411,774	
Historical	2018	Actual	$ 86,562,482	OEB-approved
Historical	2019	Actual	$ 92,419,115	
Historical	2020	Actual	$ 102,026,853	
Historical	2021	Actual	$ 104,685,608	
Bridge Year (Forecast)	2022	Forecast	$ 112,230,248	
Test Year (Forecast)	2023	Forecast	$ 107,272,461	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	6.3%	
2019	6.8%	
2020	10.4%	
2021	2.6%	
2022	7.2%	
2023	-4.4%	
Geometric Mean	5.7%	

5 **Customer Class:** Dgen

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	1,004		
Historical	2018	Actual	1,064	OEB-approved	1,119
Historical	2019	Actual	1,131		
Historical	2020	Actual	1,220		
Historical	2021	Actual	1,316		
Bridge Year	2022	Forecast	1,403		
Test Year	2023	Forecast	1,489		

	Calendar Year	Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	26,290,707	26,290,707		
Historical	2018	Actual	28,508,900	28,508,900	OEB-approved	27,034,065
Historical	2019	Actual	29,444,067	29,444,067		
Historical	2020	Actual	27,749,998	27,749,998		
Historical	2021	Actual	28,680,970	28,680,970		
Bridge Year	2022	Forecast		29,607,672		
Test Year	2023	Forecast		30,536,218		

	Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	26,185.96	26,185.96		
Historical	2018	Actual	26,806.68	26,806.68	OEB-approved	24,148.75
Historical	2019	Actual	26,033.66	26,033.66		
Historical	2020	Actual	22,745.90	22,745.90		
Historical	2021	Actual	21,791.21	21,791.21		
Bridge Year	2022	Forecast	0.00	21,105.62		
Test Year	2023	Forecast	0.00	20,503.37		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus OEB-approved	Year	Consumption Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Year	Per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017			2017				2017			
2018	5.9%		2018	8.4%	8.4%		2018	2.4%	2.4%	
2019	6.3%		2019	3.3%	3.3%		2019	-2.9%	-2.9%	
2020	7.9%		2020	-5.8%	-5.8%		2020	-12.6%	-12.6%	
2021	7.9%		2021	3.4%	3.4%		2021	-4.2%	-4.2%	
2022	6.6%		2022		3.2%		2022		-3.1%	
2023	6.2%	33.0%	2023		3.1%	13.0%	2023		-2.9%	-15.1%
Geometric Mean	8.2%	7.4%	Geometric Mean	2.9%	3.0%	3.1%	Geometric Mean	-5.9%	-4.8%	-4.0%

	Calendar Year (for 2023 Cost of Service)	Revenues		
Historical	2017	Actual	$ 3,110,861	
Historical	2018	Actual	$ 3,272,700	OEB-approved
Historical	2019	Actual	$ 3,691,568	
Historical	2020	Actual	$ 4,813,282	
Historical	2021	Actual	$ 5,053,201	
Bridge Year (Forecast)	2022	Forecast	$ 5,596,696	
Test Year (Forecast)	2023	Forecast	$ 2,457,531	

	Calendar Year	Demand (kW) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	188,672.44	191,621.39		
Historical	2018	Actual	196,614.28	196,614.28	OEB-approved	197,039.40
Historical	2019	Actual	198,345.71	198,345.71		
Historical	2020	Actual	192,801.09	192,801.09		
Historical	2021	Actual	199,269.29	199,269.29		
Bridge Year (Forecast)	2022	Forecast		205,707.82		
Test Year (Forecast)	2023	Forecast		212,159.16		

	Calendar Year	Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	187.92	190.86		
Historical	2018	Actual	184.87	184.87	OEB-approved	176.01
Historical	2019	Actual	175.37	175.37		
Historical	2020	Actual	158.03	158.03		
Historical	2021	Actual	151.40	151.40		
Bridge Year (Forecast)	2022	Forecast	0.00	146.64		
Test Year (Forecast)	2023	Forecast	0.00	142.45		

Variance Analysis

Year	Revenues Year-over-year	Test Year Versus OEB-approved	Year	Demand Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Year	Per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017			2017				2017			
2018	5.2%		2018	4.2%	2.6%		2018	-1.6%	-3.1%	
2019	12.8%		2019	0.9%	0.9%		2019	-5.1%	-5.1%	
2020	30.4%		2020	-2.8%	-2.8%		2020	-9.9%	-9.9%	
2021	5.0%		2021	3.4%	3.4%		2021	-4.2%	-4.2%	
2022	10.8%		2022		3.2%		2022		-3.1%	
2023	-56.1%		2023		3.1%	7.7%	2023		-2.9%	-19.1%
Geometric Mean	-4.6%		Geometric Mean	1.8%	2.1%	1.9%	Geometric Mean	-6.9%	-5.7%	-5.2%

6 **Customer Class:** GSd

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	5,231		
Historical	2018	Actual	5,334	OEB-approved	5,239
Historical	2019	Actual	5,411		
Historical	2020	Actual	5,348		
Historical	2021	Actual	5,367		
Bridge Year	2022	Forecast	5,420		
Test Year	2023	Forecast	5,343		

Calendar Year	Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	2,481,856,945	2,514,720,808		
2018	Actual	2,542,067,426	2,406,632,341	OEB-approved	2,457,598,720
2019	Actual	2,446,572,079	2,260,433,149		
2020	Actual	2,363,538,540	2,194,367,638		
2021	Actual	2,197,314,722	2,197,314,722		
2022	Forecast		2,200,802,374		
2023	Forecast		2,201,214,672		

Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	474,451.72	480,734.24		
2018	Actual	476,578.07	451,187.17	OEB-approved	469,078.80
2019	Actual	452,147.86	417,747.76		
2020	Actual	441,948.12	410,315.56		
2021	Actual	409,449.74	409,449.74		
2022	Forecast	0.00	406,070.14		
2023	Forecast	0.00	412,012.01		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus OEB-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017								
2018	2.0%		2.4%	-4.3%		0.4%	-6.1%	
2019	1.4%		-3.8%	-6.1%		-5.1%	-7.4%	
2020	-1.2%		-3.4%	-2.9%		-2.3%	-1.8%	
2021	0.3%		-7.0%	0.1%		-7.4%	-0.2%	
2022	1.0%			0.2%			-0.8%	
2023	-1.4%	2.0%		0.0%	-10.4%		1.5%	-12.2%
Geometric Mean	0.4%	0.5%	-4.0%	-2.6%	-2.7%	-4.8%	-3.0%	-3.2%

	Calendar Year (for 2023 Cost of Service)		Revenues	
Historical	2017	Actual	$ 130,499,079	
Historical	2018	Actual	$ 125,523,305	OEB-approved
Historical	2019	Actual	$ 135,722,149	
Historical	2020	Actual	$ 140,625,960	
Historical	2021	Actual	$ 138,165,855	
Bridge Year (Forecast)	2022	Forecast	$ 147,478,462	
Test Year (Forecast)	2023	Forecast	$ 138,343,715	

Calendar Year	Demand (kW) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	7,848,256.40	7,970,924.65		
2018	Actual	7,528,602.11	7,531,163.26	OEB-approved	7,860,142.29
2019	Actual	7,639,374.33	7,432,858.79		
2020	Actual	7,248,717.42	7,033,288.23		
2021	Actual	7,042,734.09	7,042,734.09		
2022	Forecast		7,053,912.55		
2023	Forecast		7,055,234.03		

Calendar Year	Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	1,500.34	1,523.79		
2018	Actual	1,411.44	1,411.92	OEB-approved	1,500.26
2019	Actual	1,411.82	1,373.66		
2020	Actual	1,355.41	1,315.12		
2021	Actual	1,312.35	1,312.35		
2022	Forecast	0.00	1,301.52		
2023	Forecast	0.00	1320.56		

Variance Analysis

Year	Revenues Year-over-year	Test Year Versus OEB-approved	Demand Year-over-year (Actual)	Demand Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017								
2018	-3.8%		-4.1%	-5.5%		-5.9%	-7.3%	
2019	8.1%		1.5%	-1.3%		0.0%	-2.7%	
2020	3.6%		-5.1%	-5.4%		-4.0%	-4.3%	
2021	-1.7%		-2.8%	0.1%		-3.2%	-0.2%	
2022	6.7%			0.2%			-0.8%	
2023	-6.2%			0.0%	-10.2%		1.5%	-12.0%
Geometric Mean	1.2%		-3.5%	-2.4%	-2.7%	-4.4%	-2.8%	-3.1%

7 **Customer Class:** GSe

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	88,523		
Historical	2018	Actual	88,069	OEB-approved	87,902
Historical	2019	Actual	88,774		
Historical	2020	Actual	88,904		
Historical	2021	Actual	88,236		
Bridge Year	2022	Forecast	88,547		
Test Year	2023	Forecast	88,795		

Calendar Year	Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	2,238,943,770	2,268,591,063		
2018	Actual	2,321,854,453	2,198,151,771	OEB-approved	2,207,062,032
2019	Actual	2,328,816,385	2,151,636,488		
2020	Actual	2,221,613,198	2,062,600,641		
2021	Actual	2,049,499,057	2,049,499,057		
2022	Forecast		2,038,558,517		
2023	Forecast		2,010,934,973		

Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	25,292.37	25,627.28		
2018	Actual	26,364.19	24,959.57	OEB-approved	25,108.34
2019	Actual	26,233.09	24,237.24		
2020	Actual	24,988.90	23,200.31		
2021	Actual	23,227.52	23,227.52		
2022	Forecast	0.00	23,022.24		
2023	Forecast	0.00	22,646.96		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus OEB-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
2017								
2018	-0.5%		3.7%	-3.1%		4.2%	-2.6%	
2019	0.8%		0.3%	-2.1%		-0.5%	-2.9%	
2020	0.1%		-4.6%	-4.1%		-4.7%	-4.3%	
2021	-0.8%		-7.7%	-0.6%		-7.0%	0.1%	
2022	0.4%			-0.5%			-0.9%	
2023	0.3%	1.0%		-1.4%	-8.9%		-1.6%	-9.8%
Geometric Mean	0.1%	0.3%	-2.9%	-2.4%	-2.3%	-2.8%	-2.4%	-2.5%

	Calendar Year (for 2023 Cost of Service)		Revenues	
Historical	2017	Actual	$ 154,986,316	
Historical	2018	Actual	$ 159,477,478	OEB-approved
Historical	2019	Actual	$ 170,316,084	
Historical	2020	Actual	$ 178,688,906	
Historical	2021	Actual	$ 168,784,256	
Bridge Year (Forecast)	2022	Forecast	$ 178,517,093	
Test Year (Forecast)	2023	Forecast	$ 165,984,546	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	2.9%	
2019	6.8%	
2020	4.9%	
2021	-5.5%	
2022	5.8%	
2023	-7.0%	
Geometric Mean	1.4%	

8 Customer Class: ST

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	805		
Historical	2018	Actual	817	OEB-approved	807
Historical	2019	Actual	828		
Historical	2020	Actual	877		
Historical	2021	Actual	879		
Bridge Year	2022	Forecast	881		
Test Year	2023	Forecast	904		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	15,143,367,791	15,243,194,517		
Actual	15,914,704,070	15,275,030,948	OEB-approved	15,158,047,163
Actual	15,728,095,256	15,136,788,760		
Actual	15,618,321,181	15,013,356,682		
Actual	15,068,243,946	15,068,243,946		
Forecast		15,128,250,065		
Forecast		15,253,516,392		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	18,811,637	18,935,645		
Actual	19,479,442	18,696,488	OEB-approved	18,777,530
Actual	18,995,284	18,281,146		
Actual	17,808,804	17,118,993		
Actual	17,140,995	17,140,995		
Forecast	0	17,164,879		
Forecast	0	16,873,359		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	1.5%	
2019	1.3%	
2020	5.9%	
2021	0.2%	
2022	0.3%	
2023	2.6%	12.0%
Geometric Mean	2.3%	2.9%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	5.1%	0.2%	
2019	-1.2%	-0.9%	
2020	-0.7%	-0.8%	
2021	-3.5%	0.4%	
2022		0.4%	
2023		0.8%	0.6%
Geometric Mean	-0.2%	0.0%	0.2%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	3.5%	-1.3%	
2019	-2.5%	-2.2%	
2020	-6.2%	-6.4%	
2021	-3.7%	0.1%	
2022		0.1%	
2023		-1.7%	-10.1%
Geometric Mean	-3.1%	-2.3%	-2.6%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 48,872,382		
Historical	2018	Actual	$ 47,099,962	OEB-approved	
Historical	2019	Actual	$ 47,771,500		
Historical	2020	Actual	$ 61,328,907		
Historical	2021	Actual	$ 60,917,391		
Bridge Year (Forecast)	2022	Forecast	$ 64,968,579		
Test Year (Forecast)	2023	Forecast	$ 2,920,913		

Demand (kW) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	30,285,553.51	30,758,916.71		
Actual	28,829,783.56	28,839,439.58	OEB-approved	30,587,099.68
Actual	26,468,845.63	30,918,505.31		
Actual	31,360,107.00	30,629,378.70		
Actual	30,741,356.50	30,741,356.50		
Forecast		30,863,777.51		
Forecast		30,820,095.17		

Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	37,621.81	38,209.83		
Actual	35,287.37	35,299.19	OEB-approved	37,890.78
Actual	31,967.20	37,341.19		
Actual	35,758.39	34,925.18		
Actual	34,970.06	34,970.06		
Forecast	0.00	35,018.79		
Forecast	0.00	34093.03		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	-3.6%	
2019	1.4%	
2020	28.4%	
2021	-0.7%	
2022	6.7%	
2023	-95.5%	
Geometric Mean	-43.1%	

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	-4.8%	-6.2%	
2019	-8.2%	7.2%	
2020	18.5%	-0.9%	
2021	-2.0%	0.4%	
2022		0.4%	
2023		-0.1%	0.8%
Geometric Mean	0.5%	0.0%	0.2%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	-6.2%	-7.6%	
2019	-9.4%	5.8%	
2020	11.9%	-6.5%	
2021	-2.2%	0.1%	
2022		0.1%	
2023		-2.6%	-10.0%
Geometric Mean	-2.4%	-2.3%	-2.6%

9 Customer Class: UGd

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	1,711		
Historical	2018	Actual	1,731	OEB-approved	1,735
Historical	2019	Actual	1,758		
Historical	2020	Actual	1,732		
Historical	2021	Actual	1,753		
Bridge Year	2022	Forecast	1,773		
Test Year	2023	Forecast	1,743		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1,020,320,367	1,033,831,084		
Actual	1,058,890,763	1,000,612,511	OEB-approved	1,036,884,037
Actual	1,006,715,937	904,973,322		
Actual	934,427,233	881,117,766		
Actual	883,001,667	883,001,667		
Forecast		885,377,973		
Forecast		890,838,742		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	596,329.85	604,226.23		
Actual	611,898.74	578,221.62	OEB-approved	597,599.81
Actual	572,648.43	514,774.36		
Actual	539,507.64	508,728.50		
Actual	503,718.68	503,718.68		
Forecast	0.00	499,431.99		
Forecast	0.00	511,104.95		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	1.1%	
2019	1.6%	
2020	-1.5%	
2021	1.2%	
2022	1.1%	
2023	-1.7%	0.5%
Geometric Mean	0.4%	0.1%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	3.8%	-3.2%	
2019	-4.9%	-9.6%	
2020	-7.2%	-2.6%	
2021	-5.5%	0.2%	
2022		0.3%	
2023		0.6%	-14.1%
Geometric Mean	-4.7%	-2.9%	-3.7%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	2.6%	-4.3%	
2019	-6.4%	-11.0%	
2020	-5.8%	-1.2%	
2021	-6.6%	-1.0%	
2022		-0.9%	
2023		2.3%	-14.5%
Geometric Mean	-5.5%	-3.3%	-3.8%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 26,874,979		
Historical	2018	Actual	$ 25,939,734	OEB-approved	
Historical	2019	Actual	$ 27,922,051		
Historical	2020	Actual	$ 28,140,057		
Historical	2021	Actual	$ 26,887,212		
Bridge Year (Forecast)	2022	Forecast	$ 28,668,412		
Test Year (Forecast)	2023	Forecast	$ 26,981,788		

Demand (kW) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	2,745,769.06	2,788,685.43		
Actual	2,640,406.01	2,641,234.84	OEB-approved	2,698,632.88
Actual	2,666,577.18	2,600,591.00		
Actual	2,457,503.83	2,313,812.00		
Actual	2,313,437.35	2,313,437.35		
Forecast		2,314,342.29		
Forecast		2,323,293.54		

Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1,604.77	1,629.86		
Actual	1,525.81	1,526.28	OEB-approved	1,555.34
Actual	1,516.82	1,479.29		
Actual	1,418.88	1,335.92		
Actual	1,319.73	1,319.73		
Forecast	0.00	1,305.50		
Forecast	0.00	1332.95		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	-3.5%	
2019	7.6%	
2020	0.8%	
2021	-4.5%	
2022	6.6%	
2023	-5.9%	
Geometric Mean	0.1%	

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	-3.8%	-5.3%	
2019	1.0%	-1.5%	
2020	-7.8%	-11.0%	
2021	-5.9%	0.0%	
2022		0.0%	
2023		0.4%	-13.9%
Geometric Mean	-5.6%	-3.6%	-3.7%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	-4.9%	-6.4%	
2019	-0.6%	-3.1%	
2020	-6.5%	-9.7%	
2021	-7.0%	-1.2%	
2022		-1.1%	
2023		2.1%	-14.3%
Geometric Mean	-6.3%	-3.9%	-3.8%

10 Customer Class: UGe

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	17,747		
Historical	2018	Actual	18,020	OEB-approved	18,000
Historical	2019	Actual	17,858		
Historical	2020	Actual	17,832		
Historical	2021	Actual	18,678		
Bridge Year	2022	Forecast	18,435		
Test Year	2023	Forecast	18,432		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	597,076,947	604,983,226		
Actual	616,421,544	582,495,505	OEB-approved	604,053,832
Actual	601,907,747	541,076,617		
Actual	566,647,650	534,320,163		
Actual	534,339,361	534,339,361		
Forecast		534,698,136		
Forecast		551,684,972		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	33,643.82	34,089.32		
Actual	34,207.63	32,324.94	OEB-approved	33,558.07
Actual	33,705.22	30,298.84		
Actual	31,777.01	29,964.12		
Actual	28,607.61	28,607.61		
Forecast	0.00	29,005.12		
Forecast	0.00	29,930.79		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved
2017			2017				2017			
2018	1.5%		2018	3.2%	-3.7%		2018	1.7%	-5.2%	
2019	-0.9%		2019	-2.4%	-7.1%		2019	-1.5%	-6.3%	
2020	-0.1%		2020	-5.9%	-1.2%		2020	-5.7%	-1.1%	
2021	4.7%		2021	-5.7%	0.0%		2021	-10.0%	-4.5%	
2022	-1.3%		2022		0.1%		2022		1.4%	
2023	0.0%	2.4%	2023		3.2%	-8.7%	2023		3.2%	-10.8%
Geometric Mean	0.8%	0.6%	Geometric Mean	-3.6%	-1.8%	-2.2%	Geometric Mean	-5.3%	-2.6%	-2.8%

	Calendar Year (for 2023 Cost of Service)		Revenues	
Historical	2017	Actual	$ 20,605,477	
Historical	2018	Actual	$ 21,188,636	OEB-approved
Historical	2019	Actual	$ 22,155,476	
Historical	2020	Actual	$ 22,974,564	
Historical	2021	Actual	$ 22,441,077	
Bridge Year (Forecast)	2022	Forecast	$ 23,721,824	
Test Year (Forecast)	2023	Forecast	$ 22,882,055	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	2.8%	
2019	4.6%	
2020	3.7%	
2021	-2.3%	
2022	5.7%	
2023	-3.5%	
Geometric Mean	2.1%	

11 Customer Class: Street Light

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	5,428		
Historical	2018	Actual	5,322	OEB-approved	5,467
Historical	2019	Actual	5,515		
Historical	2020	Actual	5,362		
Historical	2021	Actual	5,404		
Bridge Year	2022	Forecast	5,445		
Test Year	2023	Forecast	5,487		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	100,312,957	100,312,957		
Actual	88,526,418	88,526,418	OEB-approved	99,400,638
Actual	83,662,982	83,662,982		
Actual	78,912,138	78,912,138		
Actual	78,800,502	78,800,502		
Forecast		78,658,686		
Forecast		78,514,104		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	18,480.65	18,480.65		
Actual	16,634.05	16,634.05	OEB-approved	18,181.32
Actual	15,170.08	15,170.08		
Actual	14,716.92	14,716.92		
Actual	14,583.10	14,583.10		
Forecast	0.00	14,445.80		
Forecast	0.00	14,309.35		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved
2017			2017				2017			
2018	-2.0%		2018	-11.7%	-11.7%		2018	-10.0%	-10.0%	
2019	3.6%		2019	-5.5%	-5.5%		2019	-8.8%	-8.8%	
2020	-2.8%		2020	-5.7%	-5.7%		2020	-3.0%	-3.0%	
2021	0.8%		2021	-0.1%	-0.1%		2021	-0.9%	-0.9%	
2022	0.8%		2022		-0.2%		2022		-0.9%	
2023	0.8%	0.4%	2023		-0.2%	-21.0%	2023		-0.9%	-21.3%
Geometric Mean	0.2%	0.1%	Geometric Mean	-7.7%	-4.8%	-5.7%	Geometric Mean	-7.6%	-5.0%	-5.8%

	Calendar Year (for 2023 Cost of Service)		Revenues	
Historical	2017	Actual	$ 9,545,745	
Historical	2018	Actual	$ 8,451,263	OEB-approved
Historical	2019	Actual	$ 8,525,042	
Historical	2020	Actual	$ 8,740,370	
Historical	2021	Actual	$ 8,804,334	
Bridge Year (Forecast)	2022	Forecast	$ 9,339,933	
Test Year (Forecast)	2023	Forecast	$ 8,414,368	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	-11.5%	
2019	0.9%	
2020	2.5%	
2021	0.7%	
2022	6.1%	
2023	-9.9%	
Geometric Mean	-2.5%	

12 Customer Class: Sentinel Light

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service		Customers		
Historical	2017	Actual	22,761		
Historical	2018	Actual	21,936	OEB-approved	22,602
Historical	2019	Actual	21,189		
Historical	2020	Actual	20,218		
Historical	2021	Actual	19,886		
Bridge Year	2022	Forecast	19,558		
Test Year	2023	Forecast	19,235		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	13,865,675	13,865,675		
Actual	13,530,085	13,530,085	OEB-approved	13,573,825
Actual	12,673,057	12,673,057		
Actual	11,940,774	11,940,774		
Actual	11,675,778	11,675,778		
Forecast		11,425,710		
Forecast		11,180,868		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	609.19	609.19		
Actual	616.80	616.80	OEB-approved	600.57
Actual	598.10	598.10		
Actual	590.60	590.60		
Actual	587.15	587.15		
Forecast	0.00	584.21		
Forecast	0.00	581.28		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	-3.6%	
2019	-3.4%	
2020	-4.6%	
2021	-1.6%	
2022	-1.6%	
2023	-1.7%	-14.9%
Geometric Mean	-3.3%	-4.0%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	-2.4%	-2.4%	
2019	-6.3%	-6.3%	
2020	-5.8%	-5.8%	
2021	-2.2%	-2.2%	
2022		-2.1%	
2023		-2.1%	-17.6%
Geometric Mean	-5.6%	-4.2%	-4.7%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	1.2%	1.2%	
2019	-3.0%	-3.0%	
2020	-1.3%	-1.3%	
2021	-0.6%	-0.6%	
2022		-0.5%	
2023		-0.5%	-3.2%
Geometric Mean	-1.2%	-0.9%	-0.8%

	Calendar Year (for 2023 Cost of Service		Revenues	
Historical	2017	Actual	$ 2,373,564	
Historical	2018	Actual	$ 2,307,203	OEB-approved
Historical	2019	Actual	$ 2,331,341	
Historical	2020	Actual	$ 2,481,166	
Historical	2021	Actual	$ 2,560,299	
Bridge Year (Forecast)	2022	Forecast	$ 2,803,564	
Test Year (Forecast)	2023	Forecast	$ 2,415,120	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	-2.8%	
2019	1.0%	
2020	6.4%	
2021	3.2%	
2022	9.5%	
2023	-13.9%	
Geometric Mean	0.3%	

13 Customer Class: USL

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service		Customers		
Historical	2017	Actual	5,455		
Historical	2018	Actual	5,494	OEB-approved	5,490
Historical	2019	Actual	5,500		
Historical	2020	Actual	5,504		
Historical	2021	Actual	5,547		
Bridge Year	2022	Forecast	5,589		
Test Year	2023	Forecast	5,632		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	29,489,906	29,489,906		
Actual	28,627,176	28,627,176	OEB-approved	29,489,859
Actual	30,326,213	30,326,213		
Actual	30,732,302	30,732,302		
Actual	30,978,447	30,978,447		
Forecast		31,289,655		
Forecast		31,942,331		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	5,406.03	5,406.03		
Actual	5,210.63	5,210.63	OEB-approved	5,371.98
Actual	5,513.86	5,513.86		
Actual	5,583.63	5,583.63		
Actual	5,585.07	5,585.07		
Forecast	0.00	5,598.15		
Forecast	0.00	5,671.36		

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	0.7%	
2019	0.1%	
2020	0.1%	
2021	0.8%	
2022	0.8%	
2023	0.8%	2.6%
Geometric Mean	0.6%	0.6%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	-2.9%	-2.9%	
2019	5.9%	5.9%	
2020	1.3%	1.3%	
2021	0.8%	0.8%	
2022		1.0%	
2023		2.1%	8.3%
Geometric Mean	1.7%	1.6%	2.0%

Year	Year-over-year		Test Year Versus OEB-approved
2017			
2018	-3.6%	-3.6%	
2019	5.8%	5.8%	
2020	1.3%	1.3%	
2021	0.0%	0.0%	
2022		0.2%	
2023		1.3%	5.6%
Geometric Mean	1.1%	1.0%	1.4%

	Calendar Year (for 2023 Cost of Service		Revenues	
Historical	2017	Actual	$ 3,143,345	
Historical	2018	Actual	$ 3,135,222	OEB-approved
Historical	2019	Actual	$ 3,246,071	
Historical	2020	Actual	$ 3,169,248	
Historical	2021	Actual	$ 3,316,791	
Bridge Year (Forecast)	2022	Forecast	$ 3,543,331	
Test Year (Forecast)	2023	Forecast	$ 2,363,951	

Variance Analysis

Year	Year-over-year	Test Year Versus OEB-approved
2017		
2018	-0.3%	
2019	3.5%	
2020	-2.4%	
2021	4.7%	
2022	6.8%	
2023	-33.3%	
Geometric Mean	-5.5%	

DERIVATION OF DEMAND USING LOAD FACTOR

This exhibit has been filed separately in MS Excel format.