COST ALLOCATION

1. INTRODUCTION

This Schedule provides an overview of Hydro Ottawa's allocation of costs to its customer rate classes. Hydro Ottawa has prepared its cost allocation evidence in accordance with the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications*, dated December 9, 2024 (Filing Requirements). This Schedule includes information on cost allocation study requirements, class revenue requirements, and revenue-to-cost ratios.

2. COST ALLOCATION MODEL

Hydro Ottawa has completed a cost allocation model for each of the test years 2026-2030 using the OEB Cost Allocation Model (Model).[1] Each of the test years was modeled separately to more accurately determine the appropriate cost allocation given the rise of electrification in the load forecast. Five Excel Models are appended to this Schedule as Attachment 7-1-1(A) - OEB Workform 2026 Cost Allocation Model through Attachment 7-1-1(E) - OEB Workform 2030 Cost Allocation Model. The Models allocate Hydro Ottawa's 2026-2030 Revenue Requirement, as calculated and presented in Attachments 6-1-1(A) - 2026 Revenue Requirement Workform to 6-1-1(E) - 2030 Revenue Requirement Workform, to each rate class. The resulting annual class allocations are the basis for determining distribution rates for the Test Years 2026-2030, respectively.

Major inputs to each test year's Model include:

- Trial Balance detailing Operations, Maintenance and Administration (OM&A) and Capital costs by Uniform System of Accounts (USofA);
- Fixed Assets average cost breakdown by asset class;
- Revenue Load forecast;

[1] Hydro Ottawa has used the 2026 version of the OEB Cost Allocation Model, released on February 5, 2025

- Customer counts; and
- Supporting factors based on detailed analysis of historical data.

The Cost Allocation Models are consistent with the OEB's policies outlined in Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219),[2] Report of the Board: Review of the Board's Cost Allocation Policy (EB-2012-0383)[3] for Unmetered Loads, and OEB's letter - New Cost Allocation Policy for Street Lighting (EB-2012-0383).[4]

3. CHANGES TO THE MODEL

3.1. MISCELLANEOUS REVENUES

Hydro Ottawa has made a change to the standard cost allocation model allocators to exclude the three Standby rate classes from the allocation of Miscellaneous Revenues. Standby customers are allocated a share of Miscellaneous Revenues via their primary accounts in their respective General Service 50-1,499 kW, General Service 1,500-4,999 kW and Large Use classes. Their Standby accounts would not, in most cases, generate any additional/incremental revenues in these categories.

New allocators have been created on Tab E2 Allocators. The customer allocator titled "Total Number of Customers Excluding Standby - CCA ESB", and the composite allocator titled "5005-6225 Excluding Standby - OM&A ESB" mirror the two allocators that precede them on the Tab with the exception that Standby customer counts have been removed from the calculation. The new allocators have been applied to Other Revenue and expense accounts between USofA 4080 - Distribution Services Revenue and USofA - 4415 Equity in Earnings of Subsidiary Companies, on Tab I3 TB Data.[5]

[2] Ontario Energy Board, *Report of the Board: Review of Electricity Distribution Cost Allocation Policy*, EB-2010-0219 (March 31, 2011).
[3] Ontario Energy Board. *Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads,* EB-2012-0383 (December 19, 2023).
[4] Ontario Energy Board, *Letter re: Issuance of New Cost Allocation Policy for Street Lighting Rate Class*, EB-2012-0383 (June 12, 2015).
[5] With the exception of Account Set Up Charges (USofA 4235-1) which continues to be allocated to Standby customers.

Additionally, the allocator for USofA 4210 - Rent From Electric Property has been changed from the default allocator “Pole” to the new allocator “5005-6225 Excluding Standby - OM&A ESB”, which mirrors the allocator preceding it with the exception that Standby customer classes have been removed from the calculation. This change reflects the inclusion of duct and property rental revenues in USofA 4210. Please refer to Schedule 6-3-1 - Other Revenue Summary for details on the USofA reclassification of certain Other Revenue amounts.

3.2. COSTS AND EXPENSES NON WIRES SOLUTIONS

Hydro Ottawa has made a change to the standard cost allocation model allocators to separate the costs and expenses related to Non-Wires Solutions (NWSs) recorded in USofA 4330 - Costs and Expenses of Merchandising, Jobbing. For more information on NWSs, refer to section 9.2 NWSs to Address System Needs in Schedule 2-5-4 - Asset Management Process. The established USofA 4330 records all expenses incurred in relation to the sale of merchandise, whereas the expense related to Non Wires Solutions is more directly related to establishment of Station support for those solutions.

A new sub category USofA has thus been created on Tab I3 TB Data, labeled USofA 4330_1 – Costs and Expenses Non Wires Solutions. It takes the place of USofA 4335 which is not being used. USofA 4330_1 has been used to allocate the $2.0M that was part of USofA 4330 and that relates to support for Non Wires Solutions. It is assigned a new allocator on Tab E2 Allocators, labelled “DEMAND 1808 Excluding Standby -1808 D ESB”. The new allocator mirrors the allocator (1808 D) used to assign Station costs to customer classes, with the exception that Standby classes have been removed from the calculation.

3.3. Tab O2 FIXED CHARGE | FLOOR | CEILING

3.3.1. Change to Scenario 3

Hydro Ottawa has made a change to Scenario 3 on Tab O2 Fixed Charge|Floor|Ceiling to add in the cost of the Energy Transition, Customer Strategy and Innovation group recorded in USofA

5510 – Demonstrating and Selling Expense. The costs associated with the Energy Transition, Customer Strategy and Innovation teams are directly allocated to customer classes using Tab I9 Direct Allocation. This is a customer support group and should be added to the calculation, in Scenario 3, of the cost of having a customer. See row 226 on Tab O2 of the Model for the addition of this customer cost to the scenario. The method for calculating the direct allocation for this USofA is described in Section 5 Direct Allocation, below.

3.3.2. Implications of Floor and Ceiling Calculation on Rate Design

The OEB's cost allocation model serves as the foundation for rate design, including the determination of the balance between fixed monthly charges, which should be designed to recover the cost of grid connection and network capacity impact of a customer, and variable rate charges that capture the impact of usage of the grid. While the ceiling cost calculation on Tab O2 Fixed Charge|Floor|Ceiling of the model summarizes the cost by class of having a customer, Hydro Ottawa believes it doesn't fully align with the principle that fixed monthly rates should recover the full cost of the customer's fixed impact on the grid.[6] There are several reasons underlying this position.

Residential: Residential customers are designated as having a 100% fixed network impact by the OEB, yet the model has not been realigned to generate a corresponding ceiling rate.

General Service (GS) <50kW: Hydro Ottawa argues that GS <50kW customers have a similar grid impact to residential customers on the network and should, therefore, not pay less on their monthly bills. A comparison of GS <50kW approved 2024 fixed monthly charge of $23.15 to the approved 2024 residential rate of $34.26 reveals a difference of ($33.94 - $23.15) = $10.79 to be recovered through the variable rate. At the 2024 approved variable rate of $0.0300 per kWh, GS <50kW customers must consume at least 360 kWh to match or exceed the residential

[6] Note that the appropriateness of using the costs developed on Tab O2 as proxy for fixed costs was discussed in the 2021-2025 Rate Application process in Hydro Ottawa's response to Interrogatory 5 from Environmental Defence. Hydro Ottawa remains of the opinion that ceiling cost, as calculated on Tab O2 of the cost allocation model, is not a complete and fixed/accurate reflection of all costs that should be included in a fixed rate calculation.

distribution service charge. In 2024, 29% of GS <50kW customers fell below this threshold on a full year average basis, paying less distribution charges than residential customers. Requiring fixed rates to align with the modeled ceiling, rather than maintaining the current 25%/75% fixed/variable ratio, could exacerbate this issue by raising the monthly kWh consumption threshold required to match the residential distribution charge.

General Service (GS) 50-1,499 kW, General Service (GS) 1,500-4,999 kW and Large Use: Hydro Ottawa maintains that the ceiling rates for these three customer classes don't account for their minimum load commitments. For example, each Large Use customer obliges Hydro Ottawa to ensure that at least 5,000 kW of power is available in the grid for use of the customer as and when needed. These commitments represent fixed, customer-specific costs for the Local Distribution Company (LDC) which should, under the principle of cost causality, be reflected in the ceiling rate calculation.

Therefore, Hydro Ottawa proposes to continue setting fixed rates based on existing fixed/variable cost ratios for customer classes other than Residential, until the OEB revises the ceiling calculation to fully reflect fixed grid impact.

Refer to Schedule 8-1-2 - Fixed/Variable Proportion for more information on Hydro Ottawa's proposed fixed charges compared to cost allocation ceilings.

3.4. TAB I3 TB DATA - RATE BASE FLAG

Hydro Ottawa is proposing to inflate 2027-2030 OM&A costs from 2026 plan cost using a Custom Revenue OM&A Factor (CROF)[7] that incorporates OEB inflation, productivity, and forecast growth in capacity and customer count. As part of the rate framework, OM&A costs for the purpose of calculating working capital allowance are inflated by inflation plus growth. For this reason, the calculation of rate base on tab I3 of the cost allocation model will not match the input value from tab 4 of the Revenue Requirement Work Form (RRWF). Specifically, the "Rate

[7] CROF consists of OEB inflation minus productivity plus growth.

Base does not match" flag in cell H16 of tab I3 TB Data in each of the 2027-2030 CAM models. This difference does not impact the results of the cost allocation models as the rate base is a check and revenue requirement still aligns with what is proposed. All other RRWF input values remain in balance. For a detailed discussion of Hydro Ottawa's rate setting method please refer to Schedule 1-3-1 Rate Setting Framework.

4. COST ALLOCATION FACTORS

Hydro Ottawa has used OEB's default allocators in the Model, unless otherwise noted in this section.

4.1. I5.2 WEIGHTING FACTORS

4.1.1. Services

USofA 1855 - Services, tracks the cost of secondary overhead and underground conductors extending from the last pole to the service connection point. For underground services, it also includes the cost of the conduit encasing the service conductor. The weighting factor for Services reflects the relative level of cost of serving secondary customers in each relevant customer class.

Weighting factors have been calculated by analyzing historical capital costs recorded into USofA 1855. By categorizing capital costs for years 2003 to 2023 by customer class, an overall cost per customer for each class was calculated. As prescribed in the OEB's cost allocation model, the Residential weighting factor was set to one, and each of the other customer class weighting factors was derived using the following formula:

$$\text{Cost perCustomer}_{\text{CustomerClass}} / \text{Cost perCustomer}_{\text{Residential}} = \text{Weighting factor}$$

The resulting Services weighting factors are presented in Table 1 below and have been entered into Tab I5.2 Weighting Factors of the cost allocation model. Because the factors are based on historical data, the same factors have been used in each of the five Cost Allocation Models.

Only classes that have secondary customers per Tab I6.2 Customer Data have been assigned a weighting factor.

Table 1 – Services Weighting Factors 2026 - 2030

Class	Weighting Factor
Residential	1.0
GS <50	2.7
GS 50 to 1,499 kW	3.9
Street Light	0.2
Sentinel	1.0
Unmetered Scattered Load	0.2

4.1.2. Billing and Collection

The cost of billing and collection is allocated to customer classes on the basis of weighted number of total customers. Weighting factors have been established following the process previously approved as part of the 2021-2025 Rate Application Settlement Agreement.[8]

As the Billing and Collection weighting factors are based on forecasted spending, Hydro Ottawa is able to calculate unique factors for each of the five Test Years of the rate application period. Forecasted costs for test years 2026 to 2030 for contracted services and in-house costs were analyzed at the vendor level to determine how, and whether, each customer class utilizes each service. The costs were then allocated to each participating class based on the relative number of customers. The Residential rate class weighting factor was set to one, and the assigned cost of each of the other customer classes was compared to the cost of Residential rate class according to the following formula to arrive at a proportional weighting factor.

$$\text{Cost perCustomer}_{\text{CustomerClass}} / \text{Cost perCustomer}_{\text{Residential}} = \text{Weighting factor}$$

[8] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020).

The resulting factors, detailed in Table 2 - Billing and Collecting Weighting Factors 2026-2030, below, have been input to the cost allocation model, Tab I5.2 Weighting Factors.

Table 2 – Billing and Collecting Weighting Factors 2026-2030

Class	2026	2027	2028	2029	2030
Residential	1.000	1.000	1.000	1.000	1.000
GS<50 kW	1.164	1.156	1.153	1.149	1.143
GS 50 to 1,499 kW	8.054	7.937	7.874	7.829	7.706
GS 1,500 to 4,999 kW	7.978	7.868	7.806	7.763	7.643
Large Use	7.942	7.835	7.774	7.733	7.614
Street Light	7.999	7.867	7.785	7.718	7.568
Sentinel	0.668	0.666	0.651	0.634	0.615
Unmetered	1.367	1.336	1.318	1.289	1.252
Standby Power - All	2.634	2.562	2.558	2.544	2.516

4.2. I 7.1 METER CAPITAL

Meter Capital weighting factors represent the relative average cost of meter installation that includes material, labour and other direct costs for each customer class; larger commercial customers have multiple meters. Meter installation costs were calculated for each customer class by analyzing work order costs for the period 2003 to 2023.[9] The resulting factors proportionately align to adjusted weighting factors presented in previous rate applications.[10] The average cost per meter installed, detailed in Table 3 below, are input to Tab I7.1 Meter Capital of each of the five test year cost allocation models.

[9] This period corresponds with the large-scale implementation of smart meters in the Hydro Ottawa service area.
[10] Note that, in Hydro Ottawa's 2021 cost allocation model meter capital costs for GS 1,500-4,999 kW and Large Use classes were weighted by number of customers rather than number of meters on Tab I7.1. This has been changed in the cost allocation models currently filed for the 2026-2030 rate application.

Table 3 – Average Cost Per Meter (Installed) 2026-2030

Meter Types	2021 Approved	Proposed 2026-2030 Rate Application
Smart Meters	$166.97	$197.50
Smart Meters - Suite	$498.16	$540.17
Smart Meters - General Service < 50 kW	$366.33	$486.48
Meters General Service 50 - 1,4999 kW	$2,110.77	$2,891.62
Interval Meters General Service 1,500 - 4,999 kW	$8,605.28	$8,142.41
Interval Meters Large Use	$10,316.24	$13,650.26

4.3. I 7.2 METER READING

Meter Reading weighting factors are established, similar to Billing and Collecting, by analyzing contracted and in-house costs at the vendor level to determine the level of effort in providing meter reading for each customer class. Smart meters are assigned a weight of 1, and interval meters are assigned a weight based on proportionate costs assigned. The resulting weighting factors, summarized below, are inputted into the Cost Allocation model Tab I7.2 Meter Reading.

Table 4 – Meter Reading Weighting Factors 2026-2030

Year	Smart Meter	Interval Meter
2026	1.00	20.56
2027	1.00	20.94
2028	1.00	21.32
2029	1.00	21.69
2030	1.00	22.08

5. DIRECT ALLOCATION

Hydro Ottawa has again used Tab I9 Direct Allocation to allocate the cost of Hydro Ottawa's USofA 5510 - Demonstration and Selling Expense in the amount of $1,321K for 2026. The costs associated with the groups recorded in USofA 5510 will continue to play a key role in the development and implementation of Hydro Ottawa's NWSs strategy. Please refer to Schedule 2-5-4 - Asset Management Process, section 9.2, for additional discussion of Hydro Ottawa's NWSs plan.

The allocation is based on an analysis of direct support effort logged for each key account customer over a one year period (June 2023 to May 2024). This allocation is more reflective of the costs caused by each class than the default composite OM&A allocator which the Cost Allocation Model assigns to USofA 5510.

6. PRIMARY / SECONDARY SPLIT

As part of the 2021-2025 Approved Settlement Agreement,[11] Hydro Ottawa was required to complete a new study to support input to the cost allocation model in two major areas:

a. the appropriate split between primary, secondary and services assets; and
b. the appropriate customer count and non-coincident peak (NCP) split between primary and secondary for the Residential and GS <50 kW customer classes.

The process description and results of this study are described fully in Attachment - 7-1-1 (F) - Primary/Secondary Cost Study. The results have been incorporated into the cost models in Excel Attachments 7-1-1(A) - OEB Workform - 2026 Cost Allocation Model to 7-1-1(E) - OEB Workform - 2030 Cost Allocation Model.

[11] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020), page 27.

7. DEMAND PROFILES

The OEB's Filing Requirements restate the requirement that LDCs develop their own Coincident Peak (CP) and non-coincident peak (NCP) demand profiles for each customer class.[12] In previous rate applications, Hydro Ottawa has used default load profiles, based on a 2006 Hydro One Networks Inc. (Hydro One) study, and scaled it to test year load by class. This was used as an input to Tab I8 of the cost allocation model. For this Application, Hydro Ottawa has developed a method to calculate in-house demand factors that reflect current and expected load requirements.

Demand profiles for this Application have been based on an analysis of six years of historical load from 2018 to 2023. The same historical hourly load data was used in Hydro Ottawa's 2026-2030 sales load forecast. Please refer to Schedule 3-1-1 - Revenue Load and Customer Forecast for a discussion of that process. In subsequent years, Hydro Ottawa proposes to maintain a six-year rolling historical data set to account for the expected growth in electricity demand due to increased electrification.[13]

Hydro Ottawa used standard hourly demand profiles for unmetered classes - Streetlight, Sentinel and Unmetered Scattered loads customers.

Please refer to Attachment 7-1-1(G) - 2026 Demand Allocators for a detailed description of the methodology and calculation of demand load profile data input to Tab I8 Demand Data in the cost allocation models.

8. IMPACT OF COST STUDY INITIATIVES

The impact of each of the cost study components on the proposed 2026 revenue requirement is described in detail in Attachments 7-1-1(F) - Primary/Secondary Cost Study and 7-1-1(G) - 2026

[12] Including Secondary and Line Transformation sub classes necessary for calculating NCP values.
[13] Schedule 9-2-1 New Deferral and Variance Accounts includes the description of a proposed new Customer Specific Load Variance Account that would track the impact on Revenue/Cost ratios of the pace of electrification.

Demand Allocators. The total impact of the three initiatives is summarized in Table 5 below. The three studies most notably shift $11.9M (an increase of 6.9%) in revenue requirement to the Residential customer class from the General Service, Large Use and Street Light classes. This is almost entirely due to updated demand profiles, which were developed in-house. This is the first update to the demand profile load shapes since the Hydro One study in 2006. It is important to note that the three streams of the study do not act entirely independently. There is a compounding effect of, for example, changing both the secondary customer count and the 4NCP Demand Profile of secondary customers. This is reflected in the Compounding Impact column.

1 **Table 5 – Total Impact of Cost Study Initiatives on Proposed 2026 Revenue Requirement ($'000s)**

Customer Class	Revenue Requirement Before Cost Study	Cost Study Segments				Revenue Requirement Including Cost Study		
		Asset Classification	Secondary Customer Count	Demand Profile Study	Compounding Impact	Net Cost Allocation Study	Change	% of Total
Residential	172,637	(228)	939	11,754	(545)	184,558	11,920	6.9%
GS <50 kW	31,452	(106)	(589)	(799)	18	29,976	(1,475)	(4.7%)
GS 50 to 1,499 kW	75,864	68	(412)	(8,509)	585	67,596	(8,268)	(10.9%)
GS 1,500 to 4,999 kW	15,839	158	(1)	(1,214)	(30)	14,752	(1,088)	(6.9%)
Large Use	11,594	107	(1)	(987)	(20)	10,693	(901)	(7.8%)
Street Light	1,472	(6)	37	(331)	(9)	1,164	(308)	(20.9%)
Sentinel	11	0	1	(0)	(0)	11	1	4.8%
USL	853	(0)	26	6	(2)	883	30	3.5%
Standby Power GS 50-1,499 kW	141	3	(0)	(24)	(0)	120	(21)	(15.0%)
Standby Power GS 1,500-4,999 kW	6	0	(0)	25	1	32	26	420.4%
Standby Power Large Use	123	3	(0)	79	2	208	84	68.3%
TOTAL REVENUE REQUIREMENT	**309,993**	**(0)**	**(0)**	**(0)**	**0**	**309,993**	**(0)**	

9. ADJUSTMENTS TO COST ALLOCATION RESULTS

9.1. REVENUE TO COST RATIOS

The results from the 2026 cost allocation show that there are three rate classes that require adjustments to bring them within the OEB-Approved ranges: General Service (GS) <50 kW, Street Lighting and Unmetered Scattered Load. All three rate classes are above the Revenue/Cost ratio upper limit of 120%.

Section 2.7.3 if the Filing Requirements specify that revenue to cost ratios should be brought within approved revenue to cost ranges, with consideration for resulting bill impacts. Hydro Ottawa proposes to bring the Small Commercial and Unmetered Scattered Load classes within the upper limit in 2026. The offsetting revenue adjustment has been made to the Large User class as this is the class with the furthest revenue-to-cost ratio under 100%. This adjustment is also required in 2028 to maintain the two rate classes within the OEB-Approved range.

As depicted in Table 5 above, the Cost Allocation Study results in a cost allocation reduction of $308K (20.9%) for the Street Light class, compared to historical proportional cost splits, resulting mainly from the implementation of the in-house demand allocators review. Refer to Section 1.2 of Attachment 7-1-1(G) - 2026 Demand Allocators. The demand allocator review resulted in higher demand-related allocation to the Residential rate class and a reduction in allocation to other customer classes including Street Light. Due to the size of the adjustment necessary to bring the class to the OEB upper limit in 2026, Hydro Ottawa is proposing a rate design for 2027-2030 that will bring them within the upper limit of 120% by 2030. This took into account consideration of rate stability for all classes, and the total bill impact for Street Light specifically. Table 7 below - Current and Proposed Revenue to Cost ratios, depicts these adjustments.

The revenue shortfalls resulting from these adjustments were allocated to the Large Use customer class which has a Revenue/Cost ratio below the OEB upper-limit.

Following 2029 and 2030 cost allocation, the Large User class requires adjustments to bring them within the OEB-Approved lower bound of 85%. To bring them within the range in 2029, the offsetting adjustment was made to the Street Lighting and Small Commercial classes. In 2030, part of the offsetting adjustment was applied to the Street Lighting class to align their revenue-to-cost ratio to 120%. The remaining adjustment was allocated to Small Commercial, General Service 1,500-4,999kW and Unmetered Service Load classes on the basis of percentage of total revenue requirement. These classes were all above 100% revenue-to-cost ratio as a result of the 2030 cost allocation.

9.2 SENTINEL LIGHTING CLASS

As a result of the 2026 cost allocation, the Sentinel Lighting class remains within the 80-120 OEB-Approved range, however the resulting rate impacts from the cost allocation produce a total bill increase above 10%. As a result, Hydro Ottawa proposes to make an adjustment to the total revenue requirement to ensure total bill impacts remain below 10% while maintaining the Sentinel class within the proscribed revenue-to-cost ratios. The minor offsetting revenue adjustment has been applied to the Large Use class.

All adjustments are reflected in Sheet 11: Cost_Allocation of the respective Revenue Requirement workforms. These Excel attachments are included in this Application, as follows:

- Attachment 6-1-1(A) - OEB Workform - 2026 Revenue Requirement Workform
- Attachment 6-1-1(B) - OEB Workform - 2027 Revenue Requirement Workform
- Attachment 6-1-1(C) - OEB Workform - 2028 Revenue Requirement Workform
- Attachment 6-1-1(D) - OEB Workform - 2029 Revenue Requirement Workform
- Attachment 6-1-1(E) - OEB Workform - 2030 Revenue Requirement Workform

10. CURRENT AND PROPOSED REVENUE REQUIREMENT PROPORTIONS

Table 6 - Current and Proposed Revenue Requirement Proportions depicts the proportion of Revenue Requirement assigned to each customer class by the OEB Cost Allocation Model for

the five year rate period. The impact of electrification, discussed in Schedule - 3-1-1 Revenue Load and Customer Forecast, increases the proportion of revenue requirement allocated to the Large Use rate class over the rate period as allocation to the other General Service classes declines.

Table 6 – Current and Proposed Revenue Requirement Proportions

Rate Class	% Revenue Requirement					
	Last Study (2021)	Proposed 2026	Proposed 2027	Proposed 2028	Proposed 2029	Proposed 2030
Residential	56.40%	59.54%	59.51%	59.14%	59.00%	59.09%
GS < 50 kW	10.07%	9.67%	9.62%	9.52%	9.43%	9.37%
GS > 50 to 1,499 kW	23.89%	21.80%	21.68%	21.43%	21.05%	20.67%
GS > 1,500 to 4,999 kW	5.03%	4.76%	4.71%	4.64%	4.52%	4.40%
Large Use	3.83%	3.45%	3.70%	4.50%	5.24%	5.71%
Street Lighting	0.48%	0.38%	0.37%	0.37%	0.36%	0.36%
Sentinel Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Unmetered Scattered Load	0.27%	0.28%	0.29%	0.29%	0.29%	0.29%
Standby Power GS 50-1,499 kW		0.04%	0.04%	0.04%	0.04%	0.04%
Standby Power GS 1,500-4,999 kW	0.03%	0.01%	0.01%	0.01%	0.01%	0.01%
Standby Power Large Use		0.07%	0.07%	0.06%	0.06%	0.06%

11. CURRENT AND PROPOSED REVENUE-TO-COST RATIOS

Table 7 - Current and Proposed Revenue-to-Cost Ratios at Status Quo illustrates the output of the cost allocation models. GS <50 kW and Unmetered Scattered Load classes are above the upper band limits in 2026 and fall below the limit by the end of the five year rate period. Street Lighting class remains above the upper band limit through 2030 and Large Use falls below the lower band in 2030. Table 8 - Current and Proposed Adjusted Revenue-to-Cost Ratios provides the Revenue/Cost ratios resulting from rate mitigation to bring all rate classes within their bands

by the end of the five year rate period. Rate mitigation has been discussed in detail in Section 9 - Adjustment to Cost Allocation Results above.

Table 7 – Current and Proposed Revenue-to-Cost Ratios at Status Quo

Rate Class	Revenue-to-Cost Ratios at Status Quo						Policy Range
	Last Study (2021)	Proposed 2026	Proposed 2027	Proposed 2028	Proposed 2029	Proposed 2030	
Residential	101.10%	98.18%	98.45%	98.98%	99.20%	99.20%	85-115
GS < 50 kW	119.93%	120.59%	119.92%	120.57%	119.90%	119.81%	80-120
GS > 50 to 1,499 kW	90.40%	95.53%	95.13%	95.28%	95.77%	96.52%	80-120
GS > 1,500 to 4,999 kW	102.30%	103.75%	103.07%	103.27%	104.05%	104.96%	80-120
Large Use	86.10%	91.13%	92.95%	86.26%	84.52%	82.70%	85-115
Street Lighting	119.80%	151.40%	146.66%	130.27%	127.79%	125.00%	80-120
Sentinel Lighting	80.00%	94.11%	87.51%	88.30%	90.17%	91.50%	80-120
Unmetered Scattered Load	104.60%	124.67%	120.16%	120.62%	119.75%	119.23%	80-120
Standby Power GS 50-1,499 kW	33.20%	37.06%	48.15%	49.36%	50.52%	51.01%	
Standby Power GS 1,500-4,999 kW	33.20%	51.25%	63.55%	65.29%	66.81%	67.34%	
Standby Power Large Use	33.20%	43.22%	55.29%	59.01%	61.50%	62.20%	

Table 8 – Current and Proposed Adjusted Revenue-to-Cost Ratios

Rate Class	Adjusted Revenue-to-Cost Ratios						Policy Range
	Last Study (2021)	Proposed 2026	Proposed 2027	Proposed 2028	Proposed 2029	Proposed 2030	
Residential	101.10%	98.18%	98.44%	98.97%	99.19%	99.20%	85-115
GS < 50 kW	119.93%	119.92%	119.96%	119.93%	119.87%	119.00%	80-120
GS > 50 to 1,499 kW	90.40%	95.53%	95.13%	95.28%	95.77%	96.52%	80-120
GS > 1,500 to 4,999 kW	102.30%	103.75%	103.07%	103.27%	104.05%	104.23%	80-120
Large Use	86.10%	93.51%	94.82%	87.79%	85.00%	85.00%	85-115
Street Lighting	119.80%	145.12%	128.29%	126.85%	123.89%	120.00%	80-120
Sentinel Lighting	80.00%	87.39%	87.51%	88.30%	90.17%	91.50%	80-120
Unmetered Scattered Load	104.60%	119.97%	119.95%	120.05%	119.81%	118.38%	80-120
Standby Power GS 50-1,499 kW	33.20%	47.71%	48.30%	49.50%	50.62%	51.10%	
Standby Power GS 1,500-4,999 kW	33.20%	62.72%	63.58%	65.32%	66.83%	66.88%	
Standby Power Large Use	33.20%	54.68%	57.45%	60.95%	62.38%	64.54%	

Attachment 7-1-1(A) - OEB Workform - 2026 Cost Allocation Model

(Refer to the attachment in Excel format)

Attachment 7-1-1(B) - OEB Workform - 2027 Cost Allocation Model

(Refer to the attachment in Excel format)

Attachment 7-1-1(C) - OEB Workform - 2028 Cost Allocation Model

(Refer to the attachment in Excel format)

Attachment 7-1-1(D) - OEB Workform - 2029 Cost Allocation Model

(Refer to the attachment in Excel format)

Attachment 7-1-1(E) - OEB Workform - 2030 Cost Allocation Model

(Refer to the attachment in Excel format)

PRIMARY/SECONDARY COST STUDY

1. INTRODUCTION

This attachment outlines Hydro Ottawa's fulfillment, as part of the Approved Settlement Agreement[1] from the 2021-2025 Rate Application, of the requirement to complete a specific study to determine appropriate in-house allocation factors for the following:

1. the appropriate split between primary, secondary and services assets for cost allocation purposes; and
2. the appropriate customer count and non-coincident peak (NCP) split between primary and secondary for the Residential and GS < 50 customer classes.

The purpose of this Attachment is to describe the process and outcomes of these prescribed undertakings and to confirm the model is using the most up to date information, which has been incorporated into the 2026-2030 cost allocation models presented as Attachments 7-1-1(A) - OEB Workform 2026 Cost Allocation Model to 7-1-1(E) - OEB Workform 2030 Cost Allocation Model. Please also see Attachment 7-1-1 (G) - 2026 Demand Allocators for a description of the associated development of in-house demand profile factors.

2. ASSET SEGMENTATION

From a cost allocation point of view, Hydro Ottawa's grid has two main components: the primary grid and the secondary grid. Hydro Ottawa's primary assets carry power in the grid for all customers, therefore the costs attributable to those assets are shared proportionately by all customer classes. Most of Hydro Ottawa's larger commercial customers receive power directly from the primary grid. Secondary assets are those that step down power to a level appropriate for delivery to mainly residential and smaller business customers. Costs associated with these secondary assets are shared by those customer classes that include customers requiring this

[1] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020), page 27

service. As part of the Approved Settlement Agreement, Hydro Ottawa agreed to undertake a study to determine the appropriate primary/secondary split of these "customer-facing" distribution assets to be incorporated into the 2026 rate application. The asset classes included in the study are:

- USofA 1830 - Poles, Towers and Fixtures;
- USofA 1835 - Overhead Conductors and Devices;
- USofA 1840 - Underground Conduit; and
- USofA 1845 - Underground Conductors and Devices.

Hydro Ottawa has used the same primary/secondary splits for these four asset classes for the past several cost studies. The proportions are based on legacy calculations and assumptions that are no longer relevant to current asset mix. The methodology developed for this Application updates and solidifies the process of calculating those splits for future cost of service rate applications.

2.1 OVERHEAD AND UNDERGROUND CONDUCTORS AND CONDUIT - USofAs 1835 TO 1845

The method for calculating primary/secondary splits for three of the four asset groups is based on an analysis of work order costs charged to the asset classes. The methodology identifies a common set of characteristics that can be measured to establish a means of assigning costs of these asset classes to the primary or secondary portions of the grid. For USofAs 1835 - Overhead Conductors, 1840 - Underground Conduit and 1845 - Underground Conductors it was determined that work order costs, identified as primary or secondary according to length and cost of cable issued to those asset categories, is an appropriate basis for cost apportionment. USofA 1830 - Poles has been modeled separately as described in Section 2.2 Poles Secondary Modeling.

The apportionment process was accomplished in the following manner. The length and cost of cable issued to work orders attached to the three USofAs was extracted for the years 2005-2023 and identified as primary or secondary according to inventory description. A summary of those factors produced primary/secondary proportions for both quantity of cable issued and cost of cable issued. Costs charged to those same work orders were also accumulated, by object code, for the same test period. Material costs were apportioned to primary and secondary according to the ratio established for cost of cable issued. Labour and other costs were apportioned according to the ratio of length of cable issued. Combining these two resulted in an overall primary / secondary ratio for each of USofA 1835 and 1845. In formula format, the process looks like the following:

a. $(\text{QCable}_{primary} / \text{QCable}_{total})^{*}\ \text{WorkOrderCosts}_{labour\&other} = \text{WorkOrderCosts}_{labour\&other}\text{Primary}$
b. $\text{WorkOrderCosts}_{labour\&other}\text{Total} - \text{WorkOrderCosts}_{labour\&other}\text{Primary} = \text{WorkOrderCosts}_{labour\&other}\text{Secondary}$
c. $\text{WorkOrderCosts}_{labour\&other}\text{Primary} / \text{WorkOrderCosts}_{labour\&other}\text{Total} = \mathbf{\%WorkOrderCosts_{labour\&other}Primary}$
d. $100\% - \%\text{WorkOrderCosts}_{labour\&other}\text{Primary} = \mathbf{\%WorkOrderCosts_{labour\&other}Secondary}$

e. $(\$\text{Cable}_{primary} / \$\text{Cable}_{total})^{*}\ \text{WorkOrderCosts}_{Materialr} = \text{WorkOrderCosts}_{Material}\text{Primary}$
f. $\text{WorkOrderCosts}_{Material}\text{Total} - \text{WorkOrderCosts}_{Material}\text{Primary} = \text{WorkOrderCosts}_{Material}\text{Secondary}$
g. $\text{WorkOrderCosts}_{Material}\text{Primary} / \text{WorkOrderCosts}_{Material}\text{Total} = \mathbf{\%WorkOrderCosts_{Material}Primary}$
h. $100\% - \%\text{WorkOrderCosts}_{Material}\text{Primary} = \mathbf{\%WorkOrderCosts_{Material}Secondary}$

i. $((\text{WorkOrderCosts}_{labour\&other}\text{Total} * \mathbf{\%WorkOrderCosts_{labour\&other}Primary}) + (\text{WorkOrderCosts}_{Material}\text{Total} * \mathbf{\%WorkOrderCosts_{Material}Primary})) / \text{WorkOrderCostsTotal} = \mathbf{\%WorkOrderCostsTotal_{Primary}}$
j. $100\% - \mathbf{\%WorkOrderCostsTotal_{Primary}} = \mathbf{\%WorkOrderCostsTotal_{Secondary}}$

The following three tables show the results of this analysis.

Table 1 - Calculation of Primary Secondary Proportions for USofA 1835 (Overhead Cables)

Work Orders 2003 - 2023	Overhead Cables				
	Total	Primary		Secondary	
		Cable	%	Cable	%
Quantity of Cable Issued (Km)	4,006	3,103	77.45%	903	22.55%
Labour & Other Costs to Work Orders ($K)	**$ 128,801**	$ 99,755		$ 29,045	
Cost of Cables Issued to WOs ($K)	$ 17,870	$ 12,075	67.57%	$ 5,795	32.43%
Material Costs to Work Orders ($K)	**$ 40,360**	$ 27,271		$ 13,089	
Total Costs to Work Orders ($K)	**$ 169,160**	**$ 127,026**		**$ 42,135**	
PRIMARY/SECONDARY SPLIT		**75.09%**		**24.91%**	

Table 2 - Calculation of Primary Secondary Proportions for USofA 1845 (Underground Cables)

Work Orders 2003 - 2023	Underground Cables				
	Total	Primary		Secondary	
		Cable	%	Cable	%
Quantity of Cable Issued (Km)	4,043	3,363	83.17%	680	16.83%
Labour & Other Costs to Work Orders ($K)	**$ 134,981**	$ 112,267		$ 22,714	
Cost of Cables Issued to WOs ($K)	$102,463	$92,673	90.45%	$ 9,790	9.55%
Material Costs to Work Orders ($K)	**$158,289**	$143,166		$ 15,123	
Total Costs to Work Orders ($K)	**$293,270**	**$255,432**		**$ 37,838**	
PRIMARY/SECONDARY SPLIT		**87.10%**		**12.90%**	

Table 3 - Calculation of Primary Secondary Proportions for USofA 1840 (Underground Conduit)[2]

Work Orders 2003 - 2023	Underground Conduit				
	Total	Primary		Secondary	
		Cable	%	Cable	%
PRIMARY/SECONDARY SPLIT		**83.17%**		**16.83%**	

Table 4 below compares the break out percentages calculated above to the last rebasing rate application period. The most significant change resulting from this study lies in the allocation percentages for the two conductor accounts (USfoAs 1835 and 1845). Both overhead and underground conductors were assigned fully to their Primary sub accounts in 2021 in alignment with previous Rate Applications, in the absence of detailed analysis to support a change. The historical analysis undertaken in support of the 2026-2030 Rate Application reveals a different result. As a result, for the 2026-2030 Cost Allocation process, 24.91% of overhead, and 12.90% of underground, conductor asset costs are being assigned to Secondary sub accounts. This will have the impact of shifting related demand-allocated costs to the Residential and GS <50 kW customer rate classes. Offsetting this result, the proposed proportion of Underground Conduit (USofA 1840) asset costs allocated to Secondary sub account 1840-5 is reduced in the 2026-2030 Rate Application. The dollar impact to customer rate classes of these changes is summarized in Table 6 below.

[2] Proportions for Underground Conduit are based on Quantity of Material Issued split for Underground Cables, Table 2 above.

Table 4 - Percentage Allocation Impact on Contributed Capital, Accumulated Depreciation and Amortization Expense related to Account 1835, 1840 and 1845[3]

USofA	Description	2021-2025 Rate App	2026-2030 Rate App
1835-4	Overhead Conductors and Devices - Primary	100.00%	75.09%
1835-5	Overhead Conductors and Devices - Secondary	0.00%	24.91%
1840-4	Underground Conduit - Primary	71.90%	83.17%
1840-5	Underground Conduit - Secondary	28.10%	16.83%
1845-4	Underground Conductors and Devices - Primary	100.00%	87.10%
1845-5	Underground Conductors and Devices - Secondary	0.00%	12.90%

2.2 POLES SECONDARY MODELING - USofA 1830

The primary/secondary split of USofA 1830 - Poles is based on a count of Poles by type as recorded in HOL's Geographic Information System (GIS) asset database. To support this, a sampling program was launched to verify and complete the mapping of secondary poles in the GIS database for a defined study area. The project sampled a broad cross-section of poles in all types of geographic and demographic environments in Hydro Ottawa's service territory. Hydro Ottawa believes this approach resulted in a sufficient number of poles being mapped[4] and/or confirmed to substantiate a revised primary/secondary split.

Excluding support poles, which do not carry wires and are considered an overhead to the total poles inventory, there are three types of active poles:

- Those that carry primary conductors only;
- Those that carry primary and secondary conductors and;
- Those that carry secondary conductors only.

[3] As input to the worksheet I4 Break Out Assets of the OEB's Cost Allocation Model.
[4] Approximately 18K of ~50K poles, or 36%.

The objective of the study was to identify that portion of network poles that carry secondary cable only. Poles that carry primary conductors, with and without secondary, benefit all Hydro Ottawa customers. They are thus designated as primary by the study methodology; associated costs for this portion of the asset base are allocated to all customer classes. Poles that carry secondary conductors alone benefit only HOL's secondary customers, i.e. those that receive power over Hydro Ottawa-owned secondary distribution assets; the costs associated with this portion of the asset base are allocated only to secondary customers. The results of the sampling program, depicted in Table 5, reveal a significant reduction, from prior cost allocation studies, in the proportion of poles deemed secondary. This, in turn, results in a shifting of $2.5M in Revenue Requirement for 2026 to the larger GS Classes and Large Use from Residential, GS <50 kW, Street Light and Unmetered Scattered Load (USL) classes. The dollar impact of these proposed changes is summarized in Table 7 below.

Table 5 - Changes in Primary/Secondary Proportions for Poles Asset Class

USofA	Description	2021-2025 Rate App	2026-2030 Rate App
1830-4	Poles, Towers and Fixtures - Primary	70.00%	91.09%
1830-5	Poles, Towers and Fixtures - Secondary	30.00%	8.91%

2.3 LAND AND BUILDINGS

As an addition to the mandated primary/secondary study, the breakout of Land and Building asset costs to >50kV and <50kV subcategories was also updated. Recent construction and refurbishment of stations has resulted in a swing in the proportion of assets allocated to each as illustrated in Table 6 below.

Table 6 - Changes in Breakout of Land and Buildings Asset Classes

USofA	Description	2021-2025 Rate App	2026-2030 Rate App
1805-1	Land Station >50 kV	5.80%	89.98%
1805-2	Land Station <50 kV	94.20%	10.02%
1808-1	Buildings and Fixtures >50 kV	14.00%	63.26%
1808-2	Buildings and Fixtures <50 kV	86.00%	36.74%
1820-2	Distribution Station Equipment <50 kV Primary	92.00%	98.91%
1820-3	Distribution Station Equipment <50 kV Wholesale Meters	8.00%	1.09%

2.4 NET IMPACT ON COST ALLOCATION - PRIMARY/SECONDARY COST STUDY

While the percentage change in allocators between primary and secondary asset splits were in some cases significant, the proposed overall net impact on cost allocation is relatively small. The net effect of these adjustments to primary/secondary ratios, overlaid on the 2026 Cost Allocation Model and independent of the other streams of the cost allocation study, is to move $346K in costs to the General Service and Large Use classes from Residential, GS <50 kW and Street Light.

1 **Table 7 - Net Impact of Primary/Secondary Asset Study - 2026 Cost Allocation Model ($'000s)**

Customer Class	2026 Revenue Requirement								
	Prior to Primary / Secondary Study	Land, Stations	Poles	OH Conductors	Conduit	UG Conductors	2026 Cost Allocation Model	Change	%
Residential	172,637	122	(1,057)	1,000	(960)	667	172,409	(228)	(0.13%)
GS < 50 kW	31,452	4	(331)	313	(301)	209	31,346	(106)	(0.34%)
GS 50 to 1,499 kW	75,864	(91)	479	(453)	435	(302)	75,932	68	0.09%
GS 1,500 to 4,999 kW	15,839	(20)	536	(508)	487	(338)	15,997	158	1.00%
Large Use	11,594	(20)	386	(365)	351	(244)	11,701	107	0.93%
Street Light	1,472	3	(25)	24	(23)	16	1,467	(6)	(0.37%)
Sentinel	11	-	-	-	-	-	11	-	0.20%
USL	853	-	-	-	-	-	853	-	(0.00%)
Standby GS 50-1,499 kW	141	1	6	(6)	6	(4)	144	3	2.37%
Standby GS 1,500-4,999 kW	6	-	-	-	-	-	6	-	2.10%
Standby Large Use	123	1	6	(5)	5	(4)	126	3	2.37%
TOTAL REVENUE REQUIREMENT	**309,993**	**-**	**-**	**-**	**-**	**-**	**309,993**	**-**	

2

3. CUSTOMER SEGMENTATION

As part of the Approved Settlement Agreement,[5] Hydro Ottawa agreed to undertake a study to determine the appropriate customer count split between primary and secondary, specifically for Residential, GS <50 kW, and GS 50-1,499 kW customer classes, to be incorporated into the 2026-2030 Rate Application. In the context of the OEB's Cost Allocation Model, secondary customers are defined as those receiving power at less than 750V over Hydro Ottawa's secondary assets, defined in sub-section 2. above.

In previous Rate Applications, Hydro Ottawa has assumed all Residential and GS <50 kW customers to be secondary and relied on legacy trends to estimate the secondary customer component of commercial classes. To ensure completeness and consistency in identification of the secondary customer demographic, Hydro Ottawa has embedded a characteristic in the customer database that identifies each Service Point (SP) in the network as either Primary, Secondary or Generation.[6] Identifying the primary/secondary characteristic at the SP level ensures consistent application of the characteristic to any customer account attached to that Service Point. New Service Points receive a default characteristic when created, based on SP Type, to ensure that completeness of the characteristic inventory is maintained. Service Points that do not follow the default profile are manually updated in the customer information system.

The initial input of the characteristic to the customer database required a detailed investigation of all commercial customers with the legacy secondary tag to ensure that they were in fact using secondary assets to consume energy. This analysis reduced the number of commercial customers in the secondary category significantly, in line with the expectation that most receive energy at higher voltage from the primary network. Further analysis ensured that all similar customers in a multi-unit building received the same characteristic assignment. Monthly analytics ensure the continued completeness and accuracy of the characteristic.

[5] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020).

[6] Generation Service Points are those identified as FiT or MicroFiT, and are not included in total customer counts for the purpose of the Cost Allocation Model.

The customer count on Tab I6.2 Customer Data is a future view based on load forecasting metrics, therefore the secondary customer count remains an estimate based on that forecast. Actual customer counts, with the secondary tag, are extracted from Hydro Ottawa's customer database at the end of the last historical year and are used to create proportions by customer class that are applied to the total customer numbers to establish a defensible secondary customer count forecast. Table 8 demonstrates that process as it is applied to the 2026 Cost Allocation Model. Subsequent model years have been calculated using the same proportions.

Table 8 - Secondary Customer Counts

Customer Class	Actual Customer Count - Dec 31 2023			2026 CAM Customer Count Forecast		
	Total Customers	Secondary Customers	Proportion Secondary by Class	Total Customers	Secondary Customers	Proportion of Total Secondary
	A	B	C=B/A	D	E=D*C	F=E/E(total)
Residential	333,863	288,990	86.56%	348,287	301,475	94.54%
GS <50	26,065	17,182	65.92%	26,016	17,150	5.38%
GS 50 to 1,499 kW	3,086	96	3.11%	3,137	98	0.03%
GS 1,500 to 4,999 kW	66		-		-	-
Large Use	10		-		-	-
Street Light	7	7	100.00%	7	7	-
Sentinel	47	47	100.00%	39	39	0.01%
USL	131	126	96.18%	129	124	0.04%
TOTAL	**363,275**	**306,448**		**377,615**	**318,893**	

The Residential rate class portion of the total secondary customer count has increased, as a result of the study, from 92.53% to 94.54%, please see Table 9 below. The 98 remaining commercial secondary customers are all in the GS 50-1,499 kW rate class.

Table 9 - Secondary Customers Proportions by Customer Class

Customer Class	2026 CAM Customer Count			
	Secondary Customers at 2021 Proportions	Proportion Total Secondary	Secondary Customers Applying Cost Study	Proportion Total Secondary
Residential	348,287	92.53%	301,475	94.54%
GS <50	26,016	6.91%	17,150	5.38%
GS 50 to 1,499 kW	1,914	0.51%	98	0.03%
GS 1,500 to 4,999 kW	-	-	-	-
Large Use	-	-	-	-
Street Light	7	-	7	0-
Sentinel	39	0.01%	39	0.01%
USL	129	0.03%	124	0.04%
TOTAL	**376,392**	**100.00%**	**318,893**	**100.00%**

The overall impact of the change, based on the 2021-2025 approved cost allocation model and independent of the other two streams of the cost allocation study,[7] moves $1M in revenue requirement from the GS <50 kW rate class and GS 50-1,499 kW rate classes to Residential, Street Light, and USL rate classes. Please see Table 10 below for more details.

[7] It must be noted that the cost study streams act as compounding influences on each other. The net impact of the three streams will not be the sum of the individual studies.

1 **Table 10 - Impact of Secondary Customer Count Study ($'000s)**

Customer Class	2026 CAM Revenue Requirement			
	Before Secondary Customer Update	After Secondary Customer Update	Change	%
Residential	172,637	173,577	939	0.30%
GS < 50 kW	31,452	30,863	(589)	(0.19%)
GS 50 to 1,499 kW	75,864	75,452	(412)	(0.13%)
GS 1,500 to 4,999 kW	15,839	15,838	(1)	(0.00%)
Large Use	11,594	11,593	(1)	(0.00%)
Street Light	1,472	1,509	37	0.01%
Sentinel	11	11	1	0.00%
USL	853	880	26	0.01%
Standby GS 50-1,499 kW	141	141	(0)	(0.00%)
Standby GS 1,500-4,999 kW	6	6	(0)	(0.00%)
Standby Large Use	123	123	(0)	(0.00%)
TOTAL REVENUE REQUIREMENT	**309,993**	**309,993**	**(0)**	**0.00%**

2

DEMAND ALLOCATORS REVIEW

1. INTRODUCTION

On June 12, 2015, the OEB stated in a letter that it expected Local Distribution Companies (LDCs) to develop updated load profiles, as input to their Cost Allocation Models,[1] that reflect changes in consumption patterns at the LDC level. The *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications*, dated December 9, 2024 reiterates the requirement that LDCs develop their own load profiles for each customer rate class based on historical LDC load data.

In the 2021-2025 Approved Settlement Agreement, Hydro Ottawa further confirmed that it would develop in-house non-coincident peak (NCP) data for the two main secondary customer classes to be included in the next rebasing rate application in 2026.

> *In addition, consistent with discussion that occurred during the Technical Conference (as referenced in the response to Question 5 in undertaking JT 3.22 and page 164 of the Technical Conference transcript dated July 17, 2020), Hydro Ottawa will complete, and file with its next rebasing application, a new study on the following: … (ii) the appropriate customer count and non-coincident peak ("NCP") split between primary and secondary for the Residential and GS < 50 kW customer classes.*[2]

In previous Cost of Service Applications, Hydro Ottawa has relied on the load profiles developed by Hydro One Networks Inc. (Hydro One) in 2006, based on 2004 sample data and scaled to the Test Year revenue load forecast. For the 2026-2030 cost allocation process, Hydro Ottawa has developed a historical trend method, based on the Utilities Standards Forum (USF) Model, to update load profiles by customer class. For each historical year, from 2018 to 2023, customer

[1] Load profiles determine the Non-Coincident Peak Demand (NCP) and Coincident Peak Demand (CP) values, input in tab I8 Demand Data of the Cost Allocation Model.
[2] Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Approved Settlement Agreement*, EB-2019-0261 (September 18, 2020).

class load profiles were built from Hydro Ottawa's weather-normalized hourly load data to derive coincident peak (CP) and NCP values. The resulting load profiles were scaled to each of the 2026-2030 test year load forecasts using an annual scaling template. A trending formula was applied to the scaled results of the six years to calculate best fit values for the NCP and CP demand values for each of the test years. These values were entered into Tab I8 Demand Data in the cost allocation models.

1.1 DEMAND PROFILE METHODOLOGY

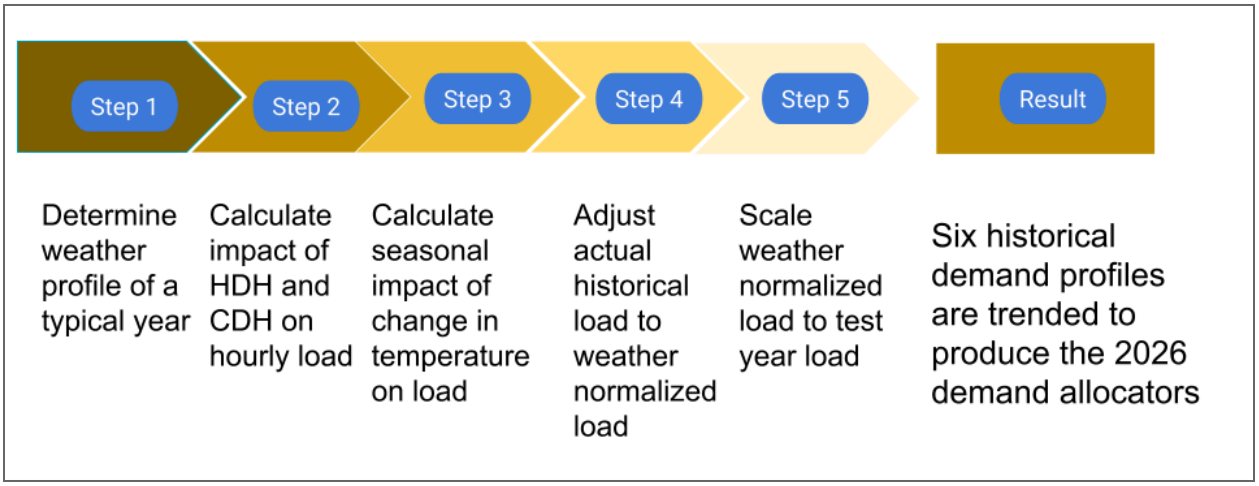
As noted, Hydro Ottawa based its demand profile methodology on the USF's Demand Allocators Model methodology (USF's DAM), which was developed by a committee of LDC participants and has been employed in three Cost of Service rate applications to date.[3]

The process calculates a weather-normalized hourly load forecast, using historical load and weather data to incorporate consideration of factors influencing fluctuations in demand seasonally, daily, and hourly. The model identifies the weather-sensitive portion of load at an hourly level and adjusts that portion of the load to reflect average weather patterns over the 10-year test period.[4] The adjusted hourly load is further modified to reflect the seasonality of the impact of a change in temperature, from one hour to the next, on load. The adjusted historical load pattern is then scaled to the total test year revenue load forecast to determine NCP and CP values. The model has been adapted to include creation of NCP values for secondary customers in the Residential, GS <50 kW, and GS 50-1,499 kW classes. This process is repeated for each of the historical years under consideration. The results for all years are then trended, at the class level, to develop best fit NCP and CP values for input to the annual cost allocation models. The methodology is described in detail below.

[3] Wellington North Power Inc.'s 2021 Cost Of Service application (EB-2020-0061), Brantford Power Inc.'s 2022 Cost of Service application (EB-2021-0009 2021) and Centre Wellington's 2025 Cost of Service Application (EB2024-0012).

[4] In its Chapter 2 filing requirements, the OEB specifies a 10-year period as the base for developing weather-normalised load shapes. For this study, the years 2014 to 2023 were analysed.

Figure 1: Demand profile methodology



Step 1: Determine weather profile of a typical year: Detailed historical hourly weather data was collected from Environment Canada weather stations at the Experimental Farm and Ottawa International Airport for the decade spanning 2014 to 2023. Gaps in the data from either site were filled by extrapolating from historical temperature trends. The two datasets were averaged to calculate an hourly temperature profile for each of the ten years. Heating Degree Hours (HDH) and Cooling Degree Hours (CDH) were calculated for each hour in each year. The base for calculating HDH and CDH values was the same one used by Itron to calculate the test year revenue load forecasts.[5]

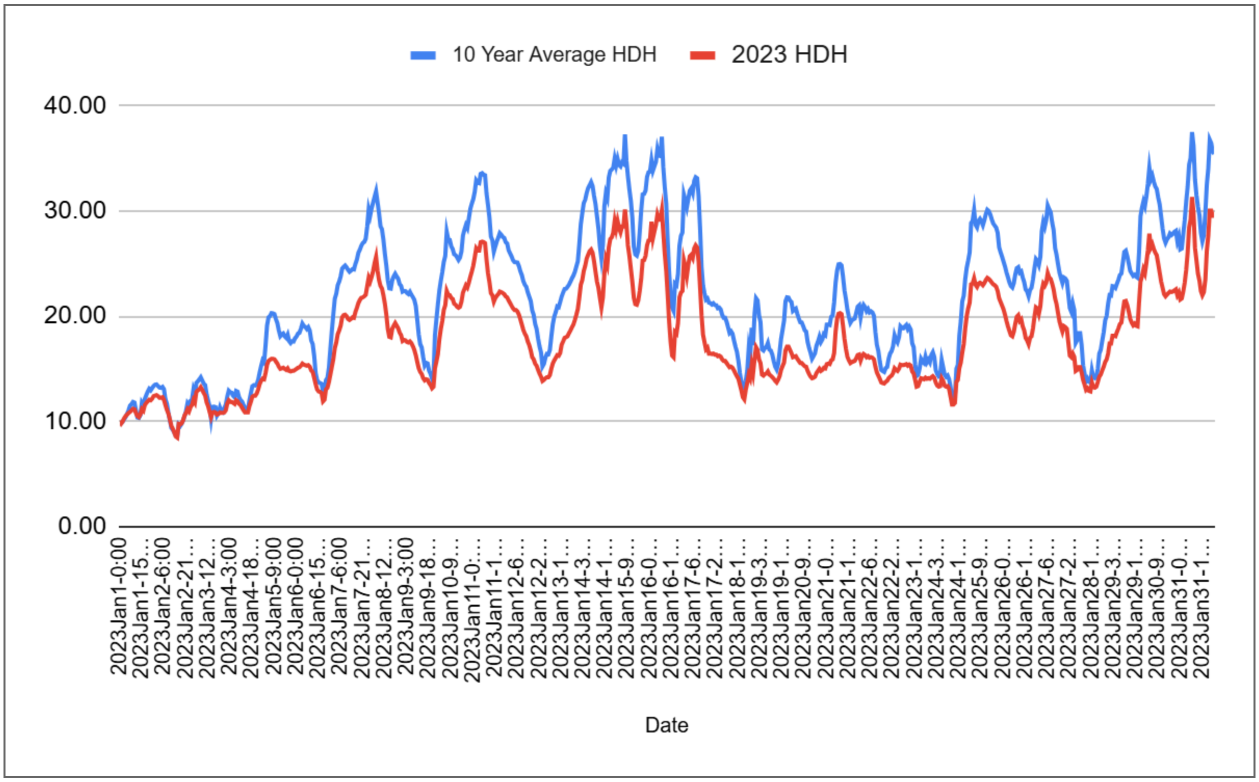
Typical hourly HDH values were calculated by first ranking and sorting each hour of each month from high to low. The ten years of equivalently ranked HDH values were then averaged to result in an average HDH for the ranked time slot. For example, the 744 HDH values for January were ranked from 1 to 744 for each of the years from 2014 to 2023, 1 representing the highest HDH value. The HDH values for the ten timeslots ranked 1 were then averaged to derive a typical HDH value for that time slot. The average HDH was compared to the actual HDH for the model year (2018-2023) being analysed to derive a percentage adjustment factor for that time slot. Figure 2 compares average HDH values for January's 744 timeslots to actual HDH for January

[5] HDH values are based on variance from 13 degrees celsius, CDH values on variance from 18 degrees celsius.

2023. Figure 3 does the same comparison on a calendar day basis. The data reveals that temperatures in 2023 were for the most part milder than the 10 year average. On this basis the actual load values for January 2023 would be adjusted upwards to reflect an average demand scenario.

Figure 2 - Average HDH Compared to 2023 HDH by Ranking

Figure 3 - Average HDH Compared to 2023 HDH by Calendar Day



Step 2: Calculate impact of HDH and CDH on hourly load: The revenue load forecast, supplied by Itron, is the basis for determining the HDH and CDH components of load. The revenue load forecast is based on a multivariate regression analysis that predicts monthly load based on a number of historical and forward-looking weather, economic and social factors, including the influence of Heating Degree Day (HDD) and Cooling Degree Day (CDD).[6] Running the Itron regression model with and without the HDD and CDD coefficients provides a monthly estimate of the impact of those two factors on load. This exercise was repeated for each weather-influenced customer class considered in the model. Table 1 below depicts the results of this analysis for the 2023 Residential customer class. For example, where the Residential rate class's January 2023 load is 695.84 GWh and where removing the HDD independent variable from the model reduces the forecast load to 526.91 GWh, then 24.28% ((695.84 -

[6] See Schedule 3-1-1 - Revenue Load and Customer Forecast for a detailed discussion of the 2026-2030 revenue load forecast.

526.91)/695.84) of the load forecast for the month of January is weather-sensitive. The same calculation is done to remove the impact of CDD from the forecast for each month. As expected the HDD factor has a greater influence on load in months other than summer, while CDD impacts the summer months when air conditioning provides the major influence. This process creates monthly HDD and CDD factors which are applied to each hour of the monthly load data to estimate the weather-sensitive portion of actual hourly load.

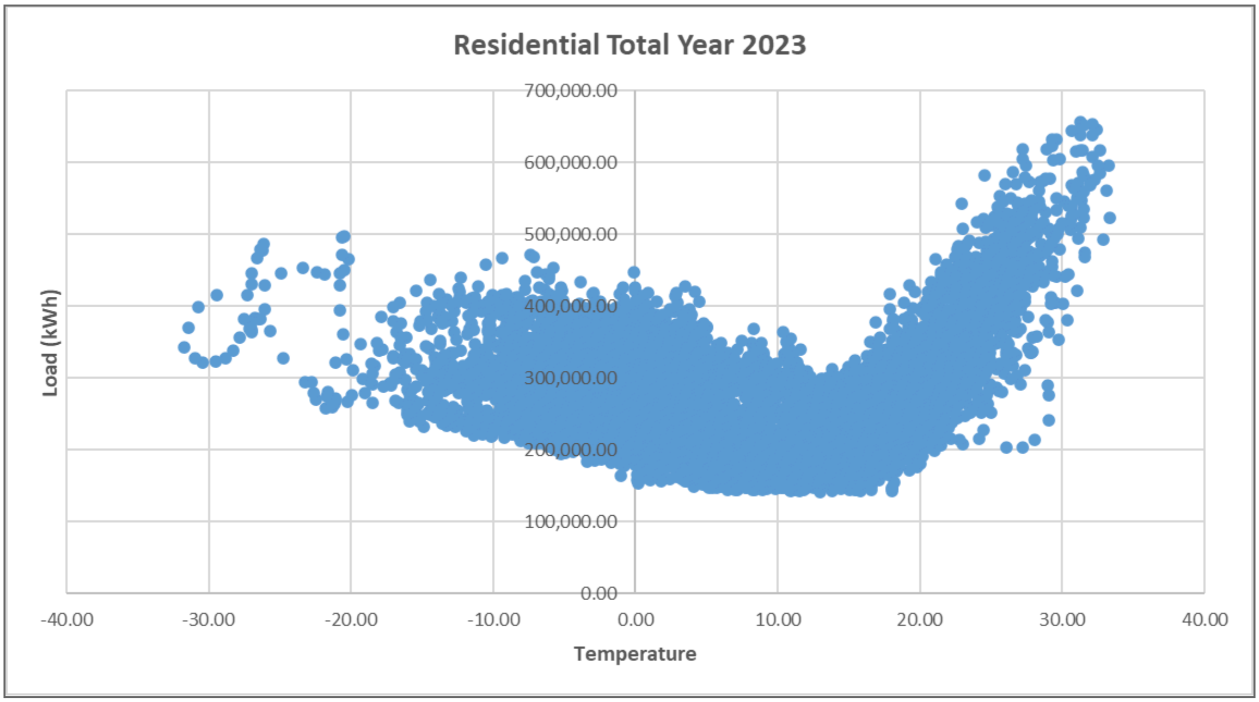
Table 1 - Impact of HDD and CDD on Residential 2023 Load

Month	Predicted Demand (gWh)	Predicted Demand excluding HDD	% Var	Month	Predicted Demand (gWh)	Predicted Demand excluding CDD	% Var
Jan-2023	695.84	526.91	24.28%	Jan-2023	695.84	695.84	0.00%
Feb-2023	635.29	467.47	26.42%	Feb-2023	635.29	635.29	0.00%
Mar-2023	624.54	492.03	21.22%	Mar-2023	624.54	624.54	0.00%
Apr-2023	520.61	465.87	10.51%	Apr-2023	520.61	520.61	0.00%
May-2023	516.22	501.52	2.85%	May-2023	516.22	485.38	5.97%
Jun-2023	629.30	629.30	0.00%	Jun-2023	629.30	488.71	22.34%
Jul-2023	770.34	770.34	0.00%	Jul-2023	770.34	499.40	35.17%
Aug-2023	571.49	571.49	0.00%	Aug-2023	571.49	497.83	12.89%
Sep-2023	560.23	559.42	0.14%	Sep-2023	560.23	484.10	13.59%
Oct-2023	567.76	536.08	5.58%	Oct-2023	567.76	540.69	4.77%
Nov-2023	588.27	477.62	18.81%	Nov-2023	588.27	588.27	0.00%
Dec-2023	664.70	526.37	20.81%	Dec-2023	664.70	664.70	0.00%
TOTAL	**7344.59**	**6524.42**		**TOTAL**	**7344.59**	**6725.36**	

Step 3: Calculate seasonal impact of change in temperature on load: Seasonality plays a role in influencing the actual impact of a change in temperature on load level. Figure 4 charts 2023 temperature and total load data to illustrate the familiar “hockey stick” relationship between the two variables. There is a much more pronounced correlation at higher temperatures, above 18 degrees celsius, where air conditioning becomes a factor. Most of the premises in the Ottawa

service region heat with gas, so the relationship is much less direct as temperatures lower. There is a range between 13 degrees and 18 degrees celsius where the correlation is quite low, indicating that temperature change at the hourly level has little direct impact on load in this range.

Figure 4 - Correlation Between Change in Temperature and Change in Load - Full Year 2023 Residential Rate Class



The correlation between temperature and load will differ from month to month. To understand the seasonal impact of temperature on load for different customer classes, Hydro Ottawa has calculated 12 monthly R-squared coefficients for each class using weather and load data from Steps 1 and 2 above. Each chart compares the average historical temperature for the month (x-axis) against the corresponding hourly electricity load (y-axis) for each customer class. The R-squared value obtained from each plot provides an indicator of the degree to which hourly load variation can be attributed to temperature change. Table 2 illustrates the coefficients for each of the weather-dependent customer classes for 2023. The coefficients for each class are higher in summer as expected however each class demonstrates a unique interdependence between temperature and load. For example summer correlations for the Commercial rate classes are less pronounced than the correlation for the Residential rate class.

Table 2 - Weather Dependent Class Temperature/Load Coefficients - 2023

Month	Residential	GS <50 kW	GS 50-1,499 kW	GS 1,500-4,999 kW	Large Use
Jan-2023	1.91%	3.41%	7.15%	4.94%	1.76%
Feb-2023	12.21%	10.65%	17.33%	7.40%	0.72%
Mar-2023	4.53%	0.04%	0.03%	0.10%	0.64%
Apr-2023	0.24%	2.13%	0.02%	2.81%	19.71%
May-2023	41.37%	32.61%	24.10%	21.72%	36.06%
Jun-2023	75.55%	61.62%	54.95%	42.14%	44.97%
Jul-2023	80.25%	66.57%	60.75%	37.71%	41.61%
Aug-2023	66.36%	59.44%	51.49%	34.41%	42.68%
Sep-2023	69.94%	60.95%	56.03%	43.84%	55.97%
Oct-2023	10.53%	19.34%	20.27%	31.23%	51.51%
Nov-2023	0.19%	0.31%	0.11%	0.02%	0.14%
Dec-2023	1.60%	5.79%	10.39%	7.04%	5.49%

Step 4: Adjust actual historical load to weather-normalized load: Actual hourly historical load shapes for the Residential, General Service and Large Use rate classes are sourced from Hydro Ottawa's data warehouse by year for the years 2018 - 2023 and validated against billed kilowatt hours. Street Light, Sentinel Lights and Unmetered Scattered Load rate classes are not supported by hourly metered data. Their load shapes have been brought forward from the 2021 Rate Application. The load shapes for the Standby classes are based on actual 2023 data for the 6 Standby customers.

Actual historical loads for the weather-influenced Rate Classes are adjusted to typical weather-normalized loads by applying the factors described in steps 1 to 3 at the hourly level. Models were created in this fashion for each of the six years from 2018 to 2023. Table 3 below provides two examples from the 2023 Residential model that illustrate the calculations to convert actual historical load to typical load.

Table 3 - Calculation of Weather-Normalized Load - 2023 Residential example

Year	Month	Day	Hour	Residential Actual Demand
				(A)
2023	1	15	19	458,652.56
2023	8	16	17	480,831.30
HDD Related Load	**HDH Weather Normalization factor**	**Temp / Load Correlation Coefficient**	**HDH Net Weather Adjustment Factor**	**HDH Net Load Adjustment**
(B)	(C)	(D)	(E) = (B)*((C)-1)*(D)	(F) = (A)*(E)
24.28%	121.60%	1.91%	0.10%	458.70
0.00%	100.00%	66.36%	0.00%	0.00
CDD Related Load	**CDH Weather Normalization factor**	**Temp / Load Correlation Coefficient**	**CDH Net Weather Adjustment Factor**	**CDH Net Load Adjustment**
(G)	(H)	(I)	(J) = (G)*((H)-1)*(I)	(K) = (A)+(F)+(J)
0.00%	100.00%	1.91%	0.00%	0.00
12.89%	109.94%	66.36%	0.85%	4,088.03
Hourly Data Adjusted For HDH & CDH Weather	**Total Change**	**% Change**		
(L) = (A) + (F) + (K)				
459,111.26	458.70	0.10%		
484,919.33	4,088.03	0.85%		

Not all customer rate classes are weather-sensitive. Street Lighting, Sentinel Lights, Standby and Unmetered Scattered Load rate classes are influenced by other factors such as hours of darkness. The load for these classes has not been weather-normalised.

Step 5: Scale weather-normalised load to test year load: The adjusted actual loads for each of the models (2018-2023) are then scaled to test year load levels on an annual basis. Itron's load forecast[7] has been developed with two separate components for the 2026-2030 rate application:

A. Itron's baseline load forecast extrapolates historical trends to predict future load for the five years. The load shape for this portion of the load forecast is derived by scaling up the historical load shape developed in steps 1-4 above.
B. Itron's electrification load forecast layers on the expected impact of the growing use of electric energy, notably in the form of space heating and electric vehicles, over the five year rate period. This portion of the load forecast has been converted to an hourly load shape using daily load shapes provided by Black and Veatch in their 2023 Decarbonization Study as Attachment 2-5-4 (F) - Decarbonization Study.

For example, the Residential rate class adjusted hourly load for 2023 is scaled to 2026 forecast baseline Residential rate class load and augmented by forecast electrification load:

$$\textit{Hourly Residential Forecast Load}_{2026} = (\textit{Hourly Residential Actual Load}_{2023} / \textit{Total Residential Actual Load}_{2023} * \textit{Total Residential Forecast Baseline Load}_{2026}) + \textit{Hourly Forecast Electrification Load}_{2026}$$

The scaled values, which total the Test Year revenue load forecast, are then analyzed to extract 2026 NCP and CP values that reflect 2023 load shape and temperature. Secondary customers in the Residential, GS <50 kW and GS 50-1,499 kW rate classes have been modeled as

[7] Attachment 3-1-1(C) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

separate classes to fulfill the requirement to develop distinct NCP values for these subclasses[8]. This sequence is repeated for each of the five test years (2026-2030) in each of the six historical demand profile models (2018-2023).

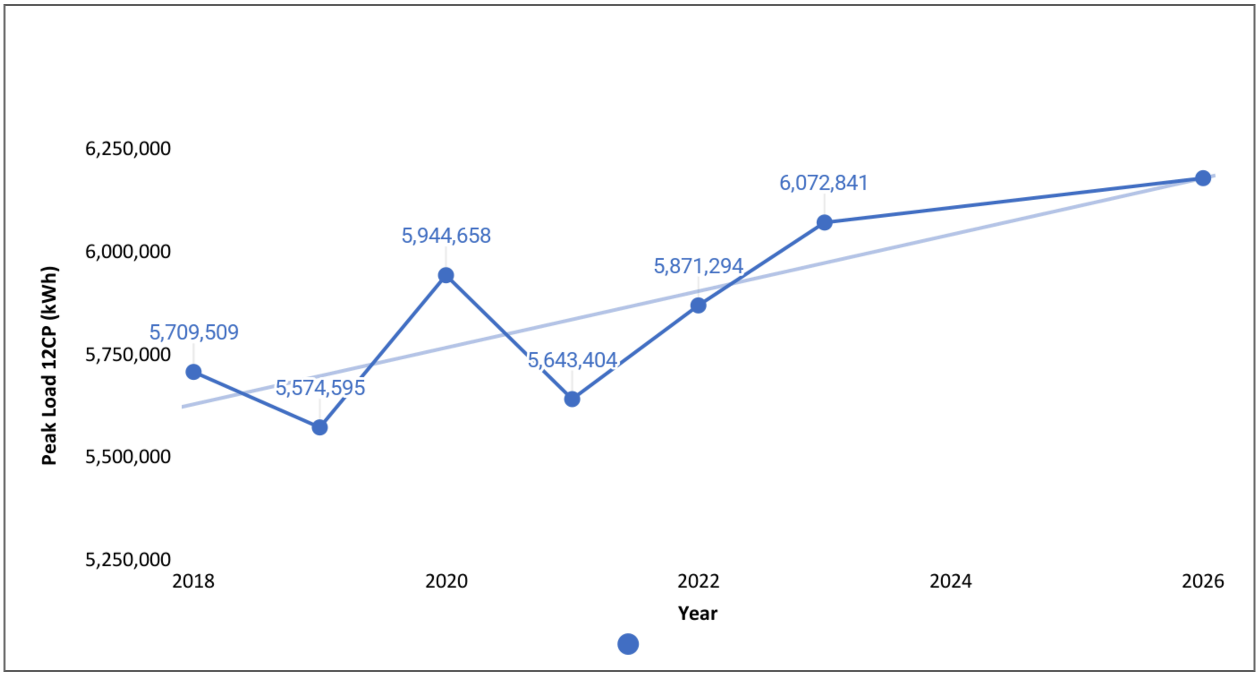
Step 6: The six historical weather-normalized models are trended to develop best fit NCP and CP factors: In each of the models, the resulting scaled hourly weather-normalised values are analysed to produce 1, 4 and 12 CP and NCP values by customer rate class. The six years of values for each customer rate class are then summarised and trended to produce forecast CP and NCP values for input to Tab I8 of the 2026 Cost Allocation Model.

The trending formula applies a best fit method to predict the next value in a sequence of numbers. Using this method rather than an average enables the capture of directional signals in the historical data. For example, if Residential rate class factors have been increasing year over year, an average will mask that trend and potentially undervalue the Residential rate class contribution to peak values.

Figure 5 illustrates the six historical Peak Load values for Residential rate class 12 CP and the calculation of a best fit 2026 forecast. The forecast value reflects the upward trend in Residential rate class peak values.

[8] See Attachment 7-1-1 (F) - Primary/Secondary Cost Study for a description of the method for forecasting secondary customers by class.

1 **Figure 5 - Residential Rate Class 12CP Forecast**



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4 Tables 4, 5 and 6 depict in tabular form the six historical annual values and best fit 2026
5 forecast of 1, 4 and 12 CP and NCP values for all customer rate classes.

1 **Table 4 - Calculation of Best Fit CP Factors 2026**

Coincident Peak	Year	Residential	GS <50kW	GS 50-1499kW	GS 1500-4999kW	Large Use	Street Lights	Sentinel Lights	USL	Standby C2	Standby C4	Standby LU
1CP	**2018**	668,917	128,188	470,210	120,974	74,281	-	-	1,463	-	125	570
	2019	641,496	123,800	451,106	119,599	73,611	-	-	1,463	-	10	183
	2020	682,517	139,108	481,162	118,512	80,621	-	-	1,459	-	8	1,076
	2021	634,210	136,971	474,361	119,427	75,542	-	-	1,444	392	-	16
	2022	607,624	122,127	442,726	110,893	73,454	-	-	1,463	-	-	-
	2023	686,652	127,660	464,418	111,111	74,462	-	-	1,479	336	208	-
	2026	**643,945**	**128,103**	**454,427**	**105,043**	**74,599**	**-**	**-**	**1,472**	**121**	**59**	**308**
4CP	**2018**	2,348,486	493,868	1,812,429	467,107	293,102	-	-	5,875	1,004	398	589
	2019	2,181,941	486,675	1,762,919	416,937	297,166	10,364	15	6,375	1,554	10	183
	2020	2,543,916	517,379	1,846,555	453,553	314,007	-	-	5,861	872	46	1,076
	2021	2,361,387	491,184	1,779,010	455,703	300,818	-	-	5,878	392	58	1,035
	2022	2,311,189	462,768	1,686,478	403,062	280,326	5,171	7	6,203	1,876	-	244
	2023	2,513,793	507,447	1,809,702	414,178	296,178	-	-	5,964	421	788	1,420
	2026	**2,538,917**	**488,503**	**1,734,056**	**387,300**	**289,338**	**2,589**	**4**	**6,018**	**1,020**	**217**	**758**
12CP	**2018**	5,709,509	1,368,867	5,021,377	1,211,252	828,647	24,308	37	19,075	2,283	620	1,757
	2019	5,574,595	1,286,482	4,794,967	1,133,138	822,500	23,424	35	19,001	1,745	10	1,182
	2020	5,944,658	1,351,299	4,883,694	1,138,622	838,873	25,534	40	19,122	2,117	46	2,499
	2021	5,643,404	1,331,139	4,899,948	1,160,793	840,030	24,689	39	19,091	1,379	59	1,284
	2022	5,871,294	1,272,777	4,676,437	1,077,951	813,244	21,235	32	18,897	1,876	10	616
	2023	6,072,841	1,396,331	5,083,884	1,164,225	854,404	19,518	29	18,866	3,042	806	2,979
	2026	**6,180,724**	**1,346,432**	**4,889,173**	**1,088,181**	**849,006**	**18,190**	**27**	**18,791**	**2,074**	**259**	**1,720**

Table 5 - Calculation of Best Fit NCP Factors

Non-Coincident Peak	Year	Residential	GS<50kW	GS 50-1499kW	GS 1500-4999kW	Large Use	Street Lights	Sentinel Lights	USL	Standby C2	Standby C4	Standby LU
1NCP	**2018**	677,296	140,326	500,181	129,976	83,871	5,496	13	2,006	1,499	387	2,551
	2019	676,048	135,833	485,569	130,029	82,428	5,361	13	2,006	1,499	387	2,551
	2020	732,340	142,066	487,533	122,729	85,689	5,156	13	2,001	1,499	387	2,551
	2021	688,598	141,546	487,334	122,824	83,509	5,168	13	2,006	1,499	387	2,551
	2022	638,445	136,130	469,606	120,814	80,487	5,187	13	2,006	1,499	387	2,551
	2023	686,652	143,231	496,184	121,594	82,730	5,122	13	2,006	1,499	387	2,551
	2026	**665,980**	**142,196**	**477,037**	**113,746**	**80,965**	**4,874**	**13**	**2,006**	**1,499**	**387**	**2,551**
4NCP	**2018**	2,561,636	535,384	1,941,749	510,512	331,244	21,504	50	7,927	5,081	1,406	9,163
	2019	2,358,653	520,590	1,875,505	486,772	324,396	20,985	50	7,927	5,081	1,406	9,163
	2020	2,662,342	548,475	1,903,648	470,505	333,257	20,482	50	7,904	5,081	1,406	9,162
	2021	2,502,190	527,766	1,854,809	472,130	325,081	20,656	50	7,927	5,081	1,406	9,163
	2022	2,425,446	518,514	1,846,833	470,709	318,871	20,738	50	7,927	5,081	1,406	9,163
	2023	2,562,324	564,302	1,919,725	467,131	323,993	20,476	50	7,927	5,081	1,406	9,163
	2026	**2,518,960**	**554,327**	**1,851,882**	**438,224**	**316,554**	**19,910**	**50**	**7,927**	**5,081**	**1,406**	**9,163**
12NCP	**2018**	6,398,959	1,470,577	5,367,563	1,338,642	932,707	61,247	123	22,390	6,990	1,951	19,336
	2019	6,040,510	1,432,614	5,197,084	1,290,846	917,174	60,897	123	22,390	6,990	1,951	19,336
	2020	6,282,254	1,456,454	5,221,220	1,276,894	914,143	61,059	123	22,327	6,990	1,951	19,335
	2021	6,053,475	1,440,445	5,170,772	1,247,044	905,666	61,451	123	22,390	6,990	1,951	19,336
	2022	6,179,084	1,434,687	5,165,027	1,243,359	907,937	61,435	123	22,390	6,990	1,951	19,336
	2023	6,342,828	1,542,014	5,306,731	1,265,914	932,685	61,350	123	22,390	6,990	1,951	19,336
	2026	**6,201,459**	**1,517,389**	**5,167,229**	**1,192,896**	**912,681**	**61,636**	**123**	**22,389**	**6,990**	**1,951**	**19,336**

1 **Table 6 - Calculation of Best Fit Secondary NCP Factors**

Year	Residential Secondary	GS <50kW Secondary	GS 50-1499kW Secondary
1NCP			
2018	609,795	84,451	
2019	611,530	80,005	
2020	645,792	83,113	21,218
2021	618,999	79,849	16,219
2022	574,701	80,508	13,763
2023	617,804	112,150	13,623
2026	**597,824**	**108,167**	**16,206**
4NCP			
2018	2,302,785	325,652	
2019	2,077,373	312,419	
2020	2,426,233	328,879	79,993
2021	2,248,677	302,076	59,617
2022	2,186,189	308,742	53,658
2023	2,309,655	393,051	52,681
2026	**2,287,281**	**375,481**	**61,487**
12NCP			
2018	5,630,221	902,088	
2019	5,298,331	849,011	
2020	5,610,292	874,730	152,019
2021	5,340,034	831,936	148,443
2022	5,451,483	861,135	144,829
2023	5,604,747	995,409	142,508
2026	**5,498,900**	**958,033**	**132,484**

1.2 IMPACT

An analysis of the Peak Demand Profiles calculated by the in-house method reveals a shift in proportionate demand-related allocation to the Residential rate class from other rate classes. While this is partially due to the new methodology, recasting the 2026 demand profile using the previous Hydro One method also reveals a shift to the Residential rate class that can be attributed to a changing revenue load forecast and overall customer counts. The shift is, however, more pronounced when the new method is incorporated, particularly in the 4NCP data, substantiating the assumption that local usage patterns have changed significantly since the Hydro One study in 2006. Tables 7, 8 and 9 provide a comparison of 2026 demand profiles calculated by the Hydro One and Hydro Ottawa in-house methods and compared to 2021 the final numbers.

The impact of the change in method is most pronounced in the 4 NCP table which shows a more than 5.8% increase in share to the Residential rate class, 70% of which is driven by the new methodology. System peaks, on the other hand, as demonstrated in the 12 CP table, reveal the opposite result. Just under three quarters of the change in the Residential rate class proportion at the system level is driven by change in load forecast and customer counts. The change in method accounts for the remaining 26%, suggesting that changing Residential rate class consumption habits over time are not by themselves driving a significant shift in the nature of system peaks.

The primary/secondary study described in Attachment 7-1-1(F) - Primary/Secondary Cost Study has resulted in significant reduction to GS 50-1,499 kW rate class secondary customer count and a corresponding increase in the Residential customer rate class's share of the secondary demand profile. While applying the methodology employed in the 2021-2025 Rate Application to 2026 forecasted customer counts would result in a small shift to the Residential rate class, the result of a review and update to customer connection, between primary and secondary (Attachment 7-1-1 (F) - Primary/Secondary Cost Study), has been far more impactful, raising the Residential rate class share to 83% from 57% in 2021.

Table 7 - 12 CP Demand Factors for 2026 Comparing Hydro One Method to Hydro Ottawa In-House Generated Factors

Class	12CP Peak Demand Profile MWh					
	2021 Final CAM		2026 Hydro One Method		2026 CAM	
Residential	4,918	*36.51%*	5,848	*41.23%*	6,181	*42.94%*
GS <50kW	1,334	*9.90%*	1,334	*9.41%*	1,346	*9.35%*
GS 50-1499kW	5,170	*38.38%*	5,040	*35.54%*	4,889	*33.97%*
GS 1500-4999kW	1,108	*8.23%*	1,091	*7.69%*	1,088	*7.56%*
Large Use	887	*6.59%*	821	*5.79%*	849	*5.90%*
Street Lighting	33	*0.25%*	25	*0.18%*	18	*0.13%*
Sentinel Lighting	0	*0.00%*	0	*0.00%*	0	*0.00%*
USL	18	*0.14%*	19	*0.14%*	19	*0.13%*
Standby 50-1499kW	0	*0.00%*	2	*0.01%*	2	*0.01%*
Standby 1500-4999kW	1	*0.00%*	0	*0.00%*	0	*0.00%*
Standby Large Use	0	*0.00%*	2	*0.01%*	2	*0.01%*

Table 8 - 4 NCP Demand Factors for 2026 Comparing Hydro One Method to Hydro Ottawa In-House Generated Factors

Class	4NCP Peak Demand Profile MWh					
	2021 Final CAM		2026 Hydro One Method		2026 CAM	
Residential	2,138	*38.18%*	2,302	*39.92%*	2,519	*44.01%*
GS <50kW	569	*10.16%*	585	*10.14%*	554	*9.69%*
GS 50-1499kW	1,986	*35.46%*	1,984	*34.39%*	1,852	*32.36%*
GS 1500-4999kW	494	*8.83%*	494	*8.57%*	438	*7.66%*
Large Use	376	*6.71%*	356	*6.18%*	317	*5.53%*
Street Lighting	25	*0.45%*	27	*0.47%*	20	*0.35%*
Sentinel Lighting	0	*0.00%*	0	*0.00%*	0	*0.00%*
USL	8	*0.13%*	8	*0.13%*	8	*0.14%*
Standby 50-1499kW	4	*0.07%*	6	*0.10%*	5	*0.09%*
Standby 1500-4999kW	1	*0.01%*	0	*0.00%*	1	*0.02%*
Standby Large Use	0	*0.00%*	5	*0.09%*	9	*0.16%*

Table 9 - 4 NCP Secondary Demand Factors for 2026 Comparing Hydro One Method to Hydro Ottawa In-House Generated Factors

Class	4NCP Peak Demand Profile - Secondary Customers MWh					
	2021 Final CAM		2026 Hydro One Method		2026 CAM	
Residential	2,138	*57.28%*	2,302	*58.83%*	2,287	*83.11%*
GS <50kW	569	*15.24%*	585	*14.95%*	375	*13.64%*
GS 50-1499kW	993	*26.60%*	992	*25.34%*	61	*2.23%*
Street Lighting	25	*0.68%*	27	*0.69%*	20	*0.72%*
Sentinel Lighting	0	*0.00%*	0	*0.00%*	0	*0.00%*
USL	8	*0.20%*	8	*0.20%*	8	*0.29%*

Tables 10 to 12 extend the comparison for the full five years of the 2026-2030 rate Application.

Table 10 - 12CP Trend

Class	12CP Peak Demand Profile MWh											
	2021 CAM Final		2026 CAM		2027 CAM		2028 CAM		2029 CAM		2030 CAM	
Residential	4,918	*36.51%*	6,181	*42.94%*	6,231	*43.17%*	6,291	*43.40%*	6,345	*43.38%*	6,359	*43.20%*
GS <50kW	1,334	*9.90%*	1,346	*9.35%*	1,345	*9.32%*	1,335	*9.21%*	1,334	*9.12%*	1,333	*9.05%*
GS 50-1499kW	5,170	*38.38%*	4,889	*33.97%*	4,858	*33.66%*	4,785	*33.01%*	4,770	*32.62%*	4,768	*32.39%*
GS 1500-4999kW	1,108	*8.23%*	1,088	*7.56%*	1,078	*7.47%*	1,056	*7.28%*	1,045	*7.15%*	1,039	*7.06%*
Large Use	887	*6.59%*	849	*5.90%*	881	*6.10%*	986	*6.80%*	1,088	*7.44%*	1,181	*8.02%*
Street Lighting	33	*0.25%*	18	*0.13%*	18	*0.13%*	19	*0.13%*	19	*0.13%*	18	*0.12%*
Sentinel Lighting	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*
USL	18	*0.14%*	19	*0.13%*	19	*0.13%*	19	*0.13%*	19	*0.13%*	19	*0.13%*
Standby 50-1499kW	0	*0.00%*	2	*0.01%*	3	*0.02%*	3	*0.02%*	3	*0.02%*	2	*0.02%*
Standby 1500-4999kW	1	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*
Standby Large Use	0	*0.00%*	2	*0.01%*	2	*0.02%*	2	*0.01%*	2	*0.01%*	2	*0.01%*

1 **Table 11 - 4NCP Trend**

Class	4NCP Peak Demand Profile MWh											
	2021 CAM Final		2026 CAM		2027 CAM		2028 CAM		2029 CAM		2030 CAM	
Residential	2,138	*38.18%*	2,519	*44.01%*	2,536	*44.07%*	2,553	*43.59%*	2,567	*43.03%*	2,585	*42.82%*
GS <50kW	569	*10.16%*	554	*9.69%*	554	*9.62%*	554	*9.45%*	554	*9.28%*	553	*9.15%*
GS 50-1499kW	1,986	*35.46%*	1,852	*32.36%*	1,843	*32.03%*	1,836	*31.35%*	1,833	*30.72%*	1,826	*30.25%*
GS 1500-4999kW	494	*8.83%*	438	*7.66%*	434	*7.54%*	430	*7.34%*	426	*7.14%*	421	*6.98%*
Large Use	376	*6.71%*	317	*5.53%*	344	*5.98%*	441	*7.53%*	543	*9.10%*	608	*10.07%*
Street Lighting	25	*0.45%*	20	*0.35%*	20	*0.35%*	20	*0.34%*	20	*0.34%*	20	*0.34%*
Sentinel Lighting	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*
USL	8	*0.13%*	8	*0.14%*	8	*0.14%*	8	*0.14%*	8	*0.14%*	8	*0.13%*
Standby 50-1499kW	4	*0.07%*	5	*0.09%*	5	*0.09%*	5	*0.09%*	5	*0.08%*	5	*0.08%*
Standby 1500-4999kW	1	*0.01%*	1	*0.02%*	1	*0.02%*	1	*0.02%*	1	*0.02%*	1	*0.02%*
Standby Large Use	0	*0.00%*	9	*0.16%*	9	*0.16%*	9	*0.15%*	9	*0.15%*	9	*0.15%*

1 **Table 12 - 4NCP Secondary Trend**

Class	4NCP Peak Demand Profile - Secondary Customers MWh											
	2021 CAM Final		2026 CAM		2027 CAM		2028 CAM		2029 CAM		2030 CAM	
Residential	2,138	*57.28%*	2,287	*83.11%*	2,294	*83.17%*	2,299	*83.21%*	2,301	*83.22%*	2,305	*83.27%*
GS <50kW	569	*15.24%*	375	*13.64%*	375	*13.59%*	375	*13.56%*	375	*13.55%*	374	*13.51%*
GS 50-1499kW	993	*26.60%*	61	*2.23%*	61	*2.22%*	61	*2.21%*	61	*2.20%*	61	*2.19%*
Street Lighting	25	*0.68%*	20	*0.72%*	20	*0.72%*	20	*0.73%*	20	*0.73%*	20	*0.73%*
Sentinel Lighting	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*	0	*0.00%*
USL	8	*0.20%*	8	*0.29%*	8	*0.29%*	8	*0.29%*	8	*0.29%*	8	*0.29%*

1.3 IMPACT ON REVENUE REQUIREMENT

Looked at in isolation, the change from the Hydro One method of establishing demand profiles to the in-house method results in a substantial increase in the revenue requirement allocated to the Residential rate class customers ($11.9M or a 6.82% increase). The offset to this increase occurs in the GS, Large Use and Street Lights rate classes. This shift supports the belief, underlying the OEB directive to develop updated demand profiles, that consumption patterns have changed in the Hydro Ottawa service area since the Hydro One study and confirms the benefit of moving to updated demand profiles.

Table 13 - Impact of Demand Profile Study on 2026 Cost Allocation ($'000s)

Customer Class	2026 CAM Revenue Requirement			
	Hydro One Method Demand Profile	After Demand Profile Update	Change	%
Residential	172,637	184,391	11,754	6.81%
Small Commercial	31,452	30,652	(799)	(2.54%)
GS 50 to 1,499 kW	75,864	67,355	(8,509)	(11.22%)
GS 1,500 to 4,999 kW	15,839	14,625	(1,214)	(7.67%)
Large Use	11,594	10,607	(987)	(8.51%)
Street Light	1,472	1,142	(331)	(22.45%)
Sentinel	11	11	(0)	(0.47%)
USL	853	859	6	0.69%
Standby GS 50-1,499 kW	141	117	(24)	(17.12%)
Standby GS 1,500-4,999 kW	6	32	25	407.36%
Standby Large Use	123	203	79	64.06%
TOTAL REVENUE REQUIREMENT	**309,993**	**309,993**	**(0)**	

UNMETERED LOADS

1. INTRODUCTION

On June 12, 2015, the OEB updated the cost allocation policy for the Street Lighting rate class and issued an update to its *Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads*.[1] As a result of the policy change, the OEB updated the cost allocation model with the 2016 version of the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications*.

As a result of the cost allocation policy change, Hydro Ottawa updated its 2016-2020 Custom Incentive Rate-Setting application[2] to incorporate the updated cost allocation model and impact on rate design as follows:

- As part of its 2016 rates, Hydro Ottawa moved Street Lighting and Unmetered Scattered Load (USL) within OEB-approved ranges;
- Sentinel Lighting was moved within the OEB's approved range over the 2016-2020 period. Effective January 1, 2020, the Sentinel Lighting rates fell within the OEB-approved range; and
- Sentinel lights were again moved within the OEB range over the 2021-2025 period. Effective January 1, 2025, Sentinel lights fell within the OEB approved range.

2. UNMETERED LOADS

Hydro Ottawa has various types of unmetered loads connected throughout its service territory. These connections are classified in the Street Lighting, Sentinel Lighting or USL rate classes. For a detailed list of unmetered load types applicable to Hydro Ottawa, please refer to Table 1 below.

[1] Ontario Energy Board, Letter RE: *Issuance of New Cost Allocation Policy for Street Lighting Rate Class*, EB-2012-0383 (June 12, 2015).
[2] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

Table 1 – Unmetered Load Types

Load Type	Description	Rate Classification
Street Lighting	Street Lighting on municipal or public roads	Street Lighting
Sentinel Lighting	Utility owned lighting on private property	Sentinel Lighting
Traffic Signals	Traffic and pedestrian crosswalks signals on public roads	USL
Intersection Cameras	Speed and Red Light Cameras on municipal or public roads	USL
Transit Shelters	Transit shelters on municipal or public roads	USL
Parks & Pathway Lighting	Publicly owned park and/or pathway lighting	USL
Decorative Lighting	Privately owned occasional festive or decorative streetscape lighting on municipal or public roads	USL
Small Services	Telephone booths, small power supplies and communication amplifiers & antennas, road & utility cathodic protection, railway signals, flasher beacons, and similar small customer loads within the public road right-of-way	USL

As part of this Application, Hydro Ottawa is not proposing any specific changes as a result of the OEB's review of the cost allocation policy for Unmetered Loads. All further changes will be considered as part of typical cost allocation and rate design. For details on the calculation of unmetered load demand profile data, please refer to Section 1.1 of Attachment 7-1-1(G) - 2026 Demand Allocators.

STANDBY SERVICE CHARGE

1. INTRODUCTION

In accordance with the requirements set out in section 2.7.1.2 of the OEB's *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications*, dated December 9, 2024 (Chapter 2 Filing Requirements), this Schedule outlines Hydro Ottawa's request for approval for final standby rates effective January 1, 2026. This schedule details the current interim standby rate design, Hydro Ottawa's communication with affected customers, and the proposal for final standby rate design.

2. REQUEST FOR FINAL STANDBY RATES

Hydro Ottawa's standby rates were first approved by the OEB on an interim basis in 2006 and these rates have remained interim in subsequent years with an understanding that a generic standby rate design would be examined and issued. In that regard, the OEB's 2015 Consultation on Rate Design for Commercial and Industrial Customers,[1] included consideration of a rate design for load displacement generation. The study concluded in 2019 with a Staff Paper[2] on Rate design that included a proposal for a Capacity Reserve Charge for General Service >50kW and Large Use classes. The intent of the charge was to replace current standby rates with a uniform charging model.

In 2023, the OEB announced the Consultation on Policy for Standby Rates.[3] This consultation again considered the implementation of a standardized Capacity Reserve Charge. On March 28, 2024, the consultation concluded with a letter from the OEB summarizing the results of the consultation. The letter did not define a comprehensive policy, however provided direction to Distributors with current interim Standby rates to apply to the OEB through their next rate application process to make those interim standby rates final.[4] In accordance with that directive and the Chapter 2 Filing

[1] Ontario Energy Board, *Rate Design for Commercial and Industrial Electricity Customers*, EB-2015-0043
[2] Ontario Energy Board, *Staff Report to the Board, Rate Design for Commercial and Industrial Electricity Customers,* EB-2015-0043 (February 21, 2019)
[3] Ontario Energy Board, *Consultation on Policy for Standby Rates*, EB- 2023-0278
[4] Ontario Energy Board, *Consultation on Policy for Standby Rates File No. EB-2023-0278* (Mar 28, 2024)

Requirements, Hydro Ottawa is applying to finalize the interim Standby rates as part of this Application.

3. CURRENT STANDBY RATES AND RATE STRUCTURE

Currently, Hydro Ottawa customers with load displacement generation equal to or greater than 500 kW and who require standby service are subject to both a standby monthly fixed service charge and volumetric charge. The fixed service charge is designed to recover the incremental cost of monitoring, billing and administration related to providing standby services and the distribution volumetric standby charge (either billed backup demand or backup overrun adjustment) is to recover the cost of maintaining standby facilities at any time. This standby rate structure is based on the customer's requirement for reserve capacity under the standby arrangement and the standby charges ensure that the Standby customer pays their fair share of Hydro Ottawa's infrastructure and operating cost to support the standby service. These standby charges also provide a source of funding to support upgrades and investments in technologies to handle increasing Distributed Energy Resource (DER) penetration.[5]

Hydro Ottawa does not charge load displacement generation with name-plate rating of below 500 kW, which supports the development of smaller DERs across Hydro Ottawa's service territory.

3.1. BILLED BACKUP DEMAND

Customers can elect to contract standby reserve capacity using their full nameplate value of the generator(s) or a lesser amount agreed to by the customer and Hydro Ottawa. The customer can elect to contract for a lesser amount if it intends to shed load when the generation is not available. This will reduce the customer's monthly cost but may expose them to the Backup Overrun Adjustment if the contracted demand is exceeded. If a customer determines that no backup capacity is required, this must be noted on a signed Electrical Operation and Maintenance Agreement. Backup Overrun Adjustments will be applied if the customer is forced to use standby

[5] For a discussion of Hydro Ottawa's plans for connecting new DERs, please see Exhibit 2-5-4 - Asset Management, Section 9.3 System Capability to Connect DER

capacity that is not contracted. Hydro Ottawa reserves the right to impose a contract for Backup Demand if a customer fails to meet its obligations and uses Hydro Ottawa for back-up service periodically. The imposed contract backup demand would be the highest of the past twelve months.

The fixed standby charge is applied to all Customers with load displacement generator(s) that exceed 499 kW. The following three examples, with a customer who has contracted 800 kW back-up demand illustrate how the monthly volumetric component of the Standby Charge is determined:

Example 1 – Generation ON for the entire bill period
In this example the Billed Backup Demand would be equal to the Contract Backup Demand of 800 kW. Where there is no Contract Backup Demand, the Billed Backup Demand is 0 kW.

Example 2 – Generation OFF for the entire bill period
In this example the Billed Backup Demand would be 0 kW. The customer is billed based on the peak demand registered on Hydro Ottawa's interval meters.

Example 3 – Generation ON and OFF during a bill period (No Backup Overruns)
In this example the Billed Backup Demand would be 550 kW. Calculated as Contract Demand of 800 kW – (Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW). This assumes that the difference between the generator OFF peak and the generator ON peak is less than the contracted demand; if not, the customer is subject to a Backup Overrun Adjustment. In this example there is no Backup Overrun Adjustment.

3.2. BACKUP OVERRUN ADJUSTMENT

The Backup Overrun Adjustment is to ensure customers contract for the appropriate amount of standby capacity. Customers must meet contract requirements by shedding load if they have contracted for an amount less than the nameplate rating.

The Backup Overrun Adjustment is calculated as follows:

(Generator OFF Peak – Generator ON Peak) – Contract Backup Demand

If the Contract Backup Demand is less than the difference between the two peaks, the Backup Overrun Adjustment charge will apply. The Backup Overrun Adjustments never exceed the total nameplate rating of the load displacement generation. Consequently, the backup overrun adjustment only applies to customers that have contracted for Backup Demand less than the generator nameplate rating.

4. PROPOSED FINAL STANDBY RATE DESIGN

For this Application, Hydro Ottawa is requesting approval to finalize the existing interim standby rates, which are valid until December 31, 2025. Effective January 1, 2026, Hydro Ottawa is proposing the following changes to the standby rate design:

1. The 2025 approved Standby monthly fixed service charge continued for the 2026-2030 rate period;
2. Standby volumetric charges only applied to Billed Backup demand above 500 kW charged at fifty percent of the distribution variable rate;
3. Backup Overrun Adjustment charges are billed using Hydro Ottawa's distribution variable rate of the applicable class;

These changes are intended to encourage more strategic development of DERs and enable Hydro Ottawa to accommodate them effectively in grid development plans.

4.1. BILLED BACKUP DEMAND

The following three examples illustrate how the proposed volumetric component of the Standby Charge for a customer who contracts 800 kW Backup Demand will be determined. In all examples, the volumetric standby charges will not apply when maintenance is performed at an agreed time or to hours where Hydro Ottawa requests specific action of the generator. The fixed standby charge is applied to all Customers with load displacement generator(s) that exceed 499 kW.

Example 1 – Generation ON for entire period
In this example the Billed Backup Demand is 300 kW, which is equal to the Contract Backup Demand 800 kW minus 500 kW. Where there is no Contract Backup Demand, the Billed Backup Demand is nil.

Example 2 – Generation OFF for entire period
In this example the Billed Backup Demand would be 0 kW. The customer is billed based on the peak demand registered on Hydro Ottawa's interval meters.

Example 3 – Generation ON and OFF during certain[6] periods (No Backup Overruns)
In this example the Billed Backup Demand would be 250 kW: Contract Demand of 800 kW – (Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW) minus the lower of Metered Peak generator ON or 500 kW. Standby customers are subject to a Backup Overrun Adjustment where the difference between the generator OFF peak and the generator ON peak is greater than the contracted amount.

4.2. BACKUP OVERRUN ADJUSTMENT

The final example applies when Generation is ON and OFF during certain[7] periods and Backup Overruns apply. In this example the customer has elected for 0 kW Contracted Demand. Billed Backup Overrun Demand would be 50 kW; Contract Demand of 0 kW – (Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW) minus the lower of Metered Peak generator ON or 500 kW. This example results in a Backup Overrun Adjustment therefore the Billed Backup Demand is applied at Hydro Ottawa's distribution variable rate.

[6] Excludes hours where Hydro Ottawa has requested generation
[7] Excludes hours where Hydro Ottawa has requested generation

Please refer to Schedule 8-1-2 - Fixed/Variable portion for further details on the 2026-2030 proposed Standby rate design.

5. COMMUNICATION WITH STANDBY CUSTOMERS

As detailed in Section 2 above, the OEB concluded the 2024 consultation on standby rates, placing the responsibility of designing Standby rates on Local Distribution Companies (LDCs). As outlined in the OEB's letter dated March 28, 2024,[8] the OEB determined LDCs should develop their own standby rate designs, tailored to their specific circumstances and encouraged them to work with customers in developing any standby rates. While this approach allows for localized solutions, it also necessitates that LDCs engage in meaningful consultations with their customers throughout the rate design process.

The timing of the issuance of this decision resulted in a condensed period for Hydro Ottawa to develop intricate rate structures, prepare comprehensive consultation materials, and conduct effective outreach to their customer base. This compressed timeline has limited the depth and breadth of Hydro Ottawa's customer engagement with Standby customers. In preparation with the 2026-2030 application, Standby customers were contacted[9] to inform them of Hydro Ottawa's plan to finalize its standby rate design. The affected customers were given notice of Hydro Ottawa's plan to seek approval to make existing interim standby charges final and propose changes to the current standby rate design to align with updated policy initiatives. Hydro Ottawa proposes to provide specific notice to existing standby customers related to the proposed final rate design as part of this Application.

6. CONSIDERATION OF FUTURE DISTRIBUTED ENERGY RESOURCES

The installation of DERs has rapidly expanded in the past ten years, transforming how, when and where energy needs are met. Embedded behind-the-meter distributed energy resources (BTM DERs) provide benefits to the system as a whole. However, additional distribution resources are

[8] Ontario Energy Board, *Consultation on Policy for Standby Rates,* EB-2023-0278 (March 28, 2024)
[9] Contacted via email in January 2025.

needed to ensure the resilience, reliability, safety, and power quality of the electric grid system while ensuring the DERs are served effectively. The costs associated with customers with BTM DERs can differ significantly from those without. BTM DERs are often operated to address individual customers' non-coincident peaks and have intermittent effects on the grid's operating reserves thus requiring deployment of LDC resources to monitor and actively address any resulting voltage issues or related mechanical wear to the system.

From 2019-2023, almost 300 new renewable DERs were connected to Hydro Ottawa's distribution system. Of these newly connected DERs, 88% were 10kW or under. Further information on these newly connected DERs are available in Schedule 2-5-4 - Asset Management Process. With the continuation of the 500 kW threshold for load displacement generation to qualify for standby charges, this ensures standby charges are not a disincentive for most generation projects. Furthermore, through the 2026-2030 period, Hydro Ottawa is exploring non-wire alternatives to address system capacity needs. As such, Hydro Ottawa is exploring incentives for non-wires solutions where there is a benefit to the distribution grid. Remuneration for beneficial DERs will be addressed separately from standby services. Please refer to section 9.4 of Schedule 2-5-4 - Asset Management Process and Schedule 6-3-5 - Other Income and Deductions for further details.