INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

1.0-VECC-1

EVIDENCE REFERENCE:

Exhibit 1, Tab 2, Schedule 3, Table 10, page 55

QUESTION(S):

a) Please provide an actual discrete objective for each "Target" on the Customer Performance Scorecard (e.g. a numeric objective).

b) If an actual target cannot be provided please explain why.

c) Please explain, what if any, relationship there is between achieving (or not) any of the targets and the rates charged to customers. For example, if any year HOL fails to meet the "Percentage of Online Billing Accounts" of 80% what difference, if any, does this make to the rates charged to customers?

d) If HOL fails to achieve an outcome target, specifically a target related to reliability or outage management, why should ratepayers not get a reduced price for their service?

RESPONSE(S):

a) Hydro Ottawa notes that the evidence reference for this interrogatory is Schedule 1-2-3 - Business Plan. Although the 2026-2030 Custom Performance Scorecard is presented as Table 10 in Schedule 1-2-3, its primary location in the evidence is Schedule 1-3-2 - Proposed Annual

Reporting - 2026-2030, where it is presented as Table 1 and each proposed measure is discussed in detail.

In Schedule 1-3-2, Hydro Ottawa provides the following explanation regarding the establishment of targets for certain measures within the Custom Performance Scorecard:

> *"The establishment of targets for individual measures (where appropriate) has been informed by recent historical data. With a few exceptions, it is generally Hydro Ottawa's intent for the targets to be assessed as five-year targets, stretching over the duration of the 2026-2030 rate period. Where possible and appropriate, the utility has provided specific, quantitative targets for particular measures. As Hydro Ottawa progresses through each year of its rate term, it will continue to assess the feasibility of setting annual targets for other measures."*

Schedule 1-3-2 also provides a rationale for why certain measures in the Custom Performance Scorecard are paired with quantitative/numeric targets and others are not.

Accordingly, Hydro Ottawa's proposal intentionally does not include a quantitative/numeric objective for each target on the Custom Performance Scorecard. Please see Schedule 1-3-2 for an explanation where no numerical target is provided.

b) Please see the response to part (a) above.

c) The relationship between achievement of a Custom Performance Scorecard target and the rates charged to customers varies by individual measure.

In specific instances, there is a correlation between target achievement and customer rates. For the particular example cited in this interrogatory—Percentage of Online Billing Accounts—there is a direct, inverse relationship between the number of customers registered for e-billing and OM&A costs incurred for customer billing. That is, a higher number of customer registrations results in lower postage and printing costs. (Please see Section 3.2.2. Online Billing

Enhancements of Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement for details on applicable cost savings). This measure is therefore an example of how Hydro Ottawa's achievement of its performance target can help lower or maintain downward pressure on customer rates. What's more, the utility has built the 80% target into its proposed OM&A expenditures. This means that, even if Hydro Ottawa falls short of its target, customers will nevertheless be safeguarded during the rate period against the costs associated with a lower adoption rate. Making the target such supports the utility covering its built in costs while also supporting reduced costs even beyond the current framework. Please see Schedule 1-3-1 - Rate Setting Framework for more details.

In addition, Hydro Ottawa acknowledges the possibility that there may be a neutral relationship between target achievement and customer rates for certain measures. However, in the case of Contact Centre Satisfaction - Transactional Feedback, the utility might significantly exceed its targeted threshold of positive customer sentiment. However, such an outcome in itself may not directly trigger or induce any changes to the cost structure of the Contact Centre or costs incurred in the Customer and Community Relations program. However, reduction in customer satisfaction often leads to increased call volumes and therefore maintaining customer satisfaction both creates positive outcomes and manages costs. Qualitatively, this measure yields valuable insights into the quality of the utility's service and customer satisfaction with the support provided.

Information and rationale for the annual performance reporting that Hydro Ottawa is proposing to undertake over the course of the upcoming five-year rate term is available in Schedule 1-3-2 - Proposed Annual Reporting - 2026-2030. Further details on the unique Earnings Sharing Mechanism which will serve as a key driver of continuous improvement in the utility's performance are available in Section 3.5 of Schedule 1-3-1 - Rate Setting Framework and the response to interrogatory 9-SEC-89.

d) The question of whether ratepayers should receive a price reduction for electricity service if a distributor fails to achieve a performance target is currently being examined by the Ontario

Energy Board (OEB) as part of its ongoing policy consultation, "Advancing Performance-based Rate Regulation" (EB-2024-0129).

A mechanism that provides ratepayers a reduced price for a certain service is essentially a performance penalty mechanism for utilities. As has been noted in this ongoing consultation, such penalty mechanisms pose a significant risk of systematically underfunding a utility. For instance, if a utility falls short of a particular metric, its revenue would be automatically reduced. This reduction, in turn, further constrains the funds available not only for improving that metric, but also for achieving other outcomes that are important to customers. It is furthermore important to note that the causes for a missed target may be partially or wholly outside of a distributor's control, such as severe weather or foreign interference.

In the Percentage of Online Billing Accounts bill example noted above, Hydro Ottawa has already built in a reduced cost. As such, any further mechanism would result in doubling the implication to the utility.

If a penalty system were to be implemented, new performance targets might be needed to better align with the balance between price and service that customers are willing to accept. This would, in turn, require a careful review of current rate-setting frameworks to ensure that cost-reduction measures don't unintentionally lead to a decrease in service quality or deviate outcomes from evolving customer preferences.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

1.0-VECC-2

EVIDENCE REFERENCE:

Exhibit 1, Tab 2, Schedule 5

QUESTION(S):

a) Please provide a table showing the Canadian annualized CPI for the years 2016 to 2024. For 2025 please show the average 6 month CPI

RESPONSE(S):

a) Please see Table A below using Bank of Canada's Canadian annualized CPI for 2016 - 2024[1].

Table A - Bank of Canada's Canadian Annualized CPI

Year	Total CPI
2016	1.4
2017	1.6
2018	2.3
2019	1.9
2020	0.7
2021	3.4
2022	6.8
2023	3.9
2024	2.4
2025 - 1st half	2.0

[1] Bank of Canada, "Consumer Price Index", https://www.bankofcanada.ca/rates/price-indexes/cpi/

Please note the specific reference in the introduction to Schedule 1-2-5 - Impacts of Inflationary Pressure is to 8.1% inflation in June 2022 and that was the Total Consumer Price Index (CPI) year over year rate in June 2022. The reference provided in Schedule 1-2-5 - Impacts of Inflationary Pressure is a Statistics Canada table (18-10-0005-01). However the data does not provide percentage but rather index values (for example 151.2 where 2017 is the base year at 100.0) and it does not include 2025 data.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

1.0-VECC-3

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 1

QUESTION(S):

a) Please explain why HOL changed the working capital compensation from its prior rate plan to include changes to Power Purchases and OM&A?

RESPONSE(S):

a) Hydro Ottawa's working capital compensation proposal has three components, one of which has remained the same from the 2021-2025 application.
   - The working capital factor of 7.5% is applied to OM&A and Cost of Power (COP) expenses.
   - In the 2021-2025 term, for 2022-2025 both OM&A and COP were adjusted by the annual OEB inflation parameter (I).
     - For 2027-2030, Hydro Ottawa is proposing to have the mechanistic (I)+(G) adjustment applied to OM&A expenses. This proposal aligns with the formulaic approach to OM&A costs embedded in working capital purposes.
     - For all years the COP expenses use the amounts calculated in Appendix 2-Z, submitted as Attachment 2-3-1(A) through (E). This approach recognizes the significant electrification built into the 2026-2030 load forecast. Please refer to Section 3.1.3 of Schedule 1-3-1 - Rate Setting Framework for further details.

Hydro Ottawa is proposing minimal annual updates in the proposed rate framework to provide customers with the benefit of rate stability and predictability through the 2026-2030 term.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

1.0-VECC-4

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 1

QUESTION(S):

a) Please revise Table 1 “Hydro Ottawa’s Current vs. Proposed Custom Rate Frameworks”, to show the 2021-025 Custom IR Framework as originally proposed in EB-2019-0261

RESPONSE(S):

a) Please see Table A below, which includes a new column to display the 2021-2025 Custom IR Framework as originally proposed in EB-2019-0261. Note that some clarifications have been added to the original Table 1 to support the comparison. These additions are in blue font in Table A below. As well, two variance accounts have been added for a more complete comparison (Lost Revenue Adjustment Mechanism (LRAM) and the COVID-19 Deferral Account).

Table A - Hydro Ottawa's Current vs. Proposed Custom Rate Frameworks

	AS PROPOSED 2021-2025 Custom IR Rate Framework	AS SETTLED 2021-2025 Custom IR Rate Framework	2026-2030 Custom IR Rate Framework
RATE-SETTING METHODOLOGY			
Year 1 Capital Related Funding	Capital Forecast with no inflation and Scientific Research & Experimental Development SR&ED tax credits contributions. Standard Rebasing for Working Capital Allowance (WCA), Cost of Capital and Payments in Lieu of Taxes (PILs).	Capital Forecast with no inflation and Scientific Research & Experimental Development SR&ED tax credits contributions included. Standard Rebasing for Working Capital Allowance (WCA), Cost of Capital and Payments in Lieu of Taxes (PILs).	Capital Forecast with inflation, stretch ($6.9M) embedded through identified efficiencies, SR&ED tax credits and accelerated Capital Cost Allowance (CCA) contribution. Standard Rebasing for WCA, Cost of Capital and PILs. Recovery of accelerated CCA for 2026.
Years 2-5: Capital Related Funding	Capital Forecast with no inflation added (base cost at 2019 pricing), with embedded capital SR&ED tax credits as a contribution.	Starting in year 2 a Capital Stretch Factor was applied of 0.60% (0.45% plus 0.15%). For the remaining years the Capital Stretch Factor was annually increased by a value of 0.60%, and SR&ED credits included.	Capital Forecast with inflation and stretch embedded through identified efficiencies and SR&ED tax credits and 2027 accelerated Capital Cost Allowance (CCA) contribution.
	Working Capital: OEB Generic WCA factor of 7.5% applied to the 2021-2025 test year Power Purchases and OM&A, escalated by inflation and growth (I + G).	**Working Capital:** OEB Generic WCA factor of 7.5% applied to the 2021 test year Power Purchases and OM&A, escalated by inflation (I)	**Working Capital:** OEB Generic WCA factor of 7.5% applied to annual estimated Power Purchases (utilizing revenue load forecast inclusive of electrification) and test year OM&A escalated by inflation and growth (I + G).
	Cost of Capital: Short-term debt rate fixed for 5 years based on OEB's 2019 parameter and a five year forecast for long-term debt and ROE.	**Cost of Capital:** Mid-term adjustment in 2024 to update for OEB cost of capital parameters for return on equity to be used for 2024 & 2025.	**Cost of Capital:** Fixed for all 5 years based on OEB's 2026 Cost of Capital parameters which will be issued in the fall of 2025.

	AS PROPOSED 2021-2025 Custom IR Rate Framework	AS SETTLED 2021-2025 Custom IR Rate Framework	2026-2030 Custom IR Rate Framework
	Payments in Lieu of Taxes: 5 year capital forecast with accelerated CCA included.	**Payments in Lieu of Taxes:** utilized the 5 year capital forecast and updated annually for inflation impact of working capital component of rate base and mid-term adjustment for ROE cost of capital parameter for 2024 and 2025. Accelerated CCA included.	**Payments in Lieu of Taxes:** Fixed for all 5 years with no adjustments. Recovery of accelerated CCA for 2026 and 2027.
Year 1 OM&A Funding	Standard Cost of Service rebasing (includes OM&A SR&ED as a reduction to OM&A)	Standard Cost of Service rebasing (includes OM&A SR&ED as a reduction to OM&A in base year)	Standard Cost of Service rebasing with embedded stretch (includes OM&A SR&ED as a reduction to OM&A in base year)
Years 2-5 OM&A Funding	Year 1 escalated by a static **Custom Price Escalation Factor (CPEF) of 2.51%;** composed of **I - X + G** where:	Year 1 escalated by annual **Custom Price Escalation Factor (CPEF)** composed of **I – X + G** where:	Year 1 escalated by annual **Custom Revenue OM&A Factor (CROF)** composed of **I – X + G** where:
	I = Static Inflation Factor = 2.26%	I = OEB Inflation Factor	I = OEB Inflation Factor
	X = 0.15% derived from Clearspring Energy Advisors Benchmarking analysis; with removal of costs related to once-in-a-generation investments (Facilities Renewal Program and Cambrian MTS)	X = 0.45% derived from PEG Model (based on under reporting of secondary lines)	X = 0.15%, based on the outputs of the adjusted PEG's Model (Attachment 1-3-3 (A) - PEG Benchmarking Analysis) with an adjustment to recognize the embedded stretch productivity in base OM&A capped at maintaining a 0.15% stretch factor.
	G = 0.40% calculated using forecasted customer growth rate based on the 2021-2025 load forecast multiplied by a 0.35 scaling factor.	G = 0.34% calculated using forecasted customer growth rate based on the 2021-2025 load forecast multiplied by a 0.35 scaling factor.	G = 3.23% calculated using forecasted customer and system capacity growth, weighted using the assumptions in the OEB's cost allocation model for OM&A.

	AS PROPOSED 2021-2025 Custom IR Rate Framework	AS SETTLED 2021-2025 Custom IR Rate Framework	2026-2030 Custom IR Rate Framework
Other Revenue	Mix of some other revenue set for 5 years while other revenue and rates escalated by static CPEF formula (I-X+G = 2.51%)	Mix of some other revenue set for 5 years while other revenue and rates were updated based on OEB approved inflation.	Set both rates and revenue for 5 years. Where rates are proposed to be adjusted in years 2 to 5 based on inflation, set rate of 2.1% for all four years (no adjustment based on the OEB approved inflation factor)
OTHER ELEMENTS OF THE RATE FRAMEWORK			
Earnings Sharing Mechanism	Asymmetrical ESM account on a 50/50 basis above a deadband of 150 basis points	Asymmetrical ESM account on a 50/50 basis with no dead band	Asymmetrical ESM account on a 50/50 basis above a dead band of 150 basis points if the utility's efficiency cohort determined by the adjusted PEG (as described in Attachment 1-3-3 (A) - PEG Benchmarking Analysis) remains constant or reduces over the rate period.
Performance Incentives	N/A	A Performance Outcomes Accountability Mechanism deferral account to link the execution of certain aspects of Hydro Ottawa's DSP to the recovery of amounts included in the agreed-upon revenue requirement	
Off-Ramp and Z-Factor	In accordance with standard OEB policy	In accordance with standard OEB policy	In accordance with standard OEB policy
Capital Variance Accounts	***Symmetrical*** sub-account to track over and underspending in System Access	***Asymmetrical*** sub-account to track underspending in System Access (excluding plant relocation and residential expansion).	***Asymmetrical*** sub-account to track underspending in System Access (except investments related to third-party plant relocations, and commercial and residential expansions (Growth Capital Development Additions which are tracked in another sub-account as detailed below)

	AS PROPOSED 2021-2025 Custom IR Rate Framework	AS SETTLED 2021-2025 Custom IR Rate Framework	2026-2030 Custom IR Rate Framework
	Asymmetrical sub-account to track underspending in System Renewal and System Service	***Asymmetrical*** sub-account to track underspending in System Renewal and System Service	***Asymmetrical*** sub-account to track underspending in System Renewal and System Service (except capacity upgrades to enable housing developments which are tracked in another sub-account as detailed below)
	Asymmetrical sub-account to track underspending in General Plant	***Asymmetrical*** sub-account to track underspending in General Plant	***Asymmetrical*** sub-account to track underspending in General Plant
	See above	***Partial Symmetrical and partial Asymmetrical*** sub-account to record System Access over/underspending driven by third-party plant relocations and residential expansion. (See System Access Account above).	***Symmetrical*** sub-account to record over/underspending in System Access investments related by third-party plant relocations, commercial and residential expansion, and in System Service investments related to capacity upgrades to enable housing developments (together as Growth Capital Development Additions).
CCRA Variance Account	***Symmetrical*** account for CCRA payments to HONI including both new contribution and true-ups	***Symmetrical*** account for CCRA payments to HONI including both new contribution and true-ups	***Symmetrical*** account for CCRA payments to HONI including both new contributions and true-ups
Non-Wires Solutions (NWS) Variance Account	NWS are new and offset of reduced capital captured in CVA was not contemplated	NWS are new and offset of reduced capital captured in CVA was not contemplated	***Symmetrical*** account to capture NWS costs in other revenue and OM&A, net of any external funding related to NWS

	AS PROPOSED 2021-2025 Custom IR Rate Framework	AS SETTLED 2021-2025 Custom IR Rate Framework	2026-2030 Custom IR Rate Framework
Large Load Revenue Variance Account	**LRAMVA** - Maintain for CDM embedded in Revenue Load Forecast[1]	**LRAMVA** - Maintain for CDM embedded in and removed from Revenue Load Forecast	***Symmetrical*** account to capture revenue variances associated with differences in volume and timing of large loads adjusted into the load forecast (as presented in Table 8 of Schedule 3-1-1) to actual billing load, net of contribution adjustments, No LRAMVA requested
Tariff Impact Deferral Account	**COVID-19 Deferral Account -** Impacts Arising from the COVID-19 Emergency[2]	**COVID-19 Deferral Account -** Only the use of the COVID Account if "a material change in Ontario's public health and economic circumstances" occurred	***Asymmetrical*** account to track global tariff related costs

1

[1] LRAMVA has been included as a comparison to the Large Load variance Account request as both relate partially to policy driven load impacting initiatives and are also driven by customer timing decisions that are beyond the typical Revenue Load Forecast methodology.
[2] Although underlying drivers exist, the COVID-19 Account has been added to the Original Table as a comparison to another economically impactful event that was part of the proposed and approved 2021-2025 rate framework.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

1.0-VECC-5

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 1

Table 3 – 2026-2030 Required and Proposed Capital Expenditures ($'000 000s)

	2026-2030			
	Required	**Proposed**	**Stretch $**	**Stretch %**
Capital Expenditures	$1,230	$1,195	($35)	(2.9%)

QUESTION(S):

a) According to Appendix 2-AB HOL's net capital variance from plan to actual ranged from -6.8% to 55.7% between 2021 and as estimated for 2025. Given the range in variability as between planned and actual capital costs how is stretch of 2.9% meaningful?

RESPONSE(S):

a) Please see Schedule 2-1-1 - Rate Base Overview for a variance analysis and discussion on the main drivers of the higher in-service additions, which at a high level are: Unprecedented Supply Chain Disruption, Customer Connections Volume, Complexity, and Cost, Increased Emergency Renewal Work due to Major Storms and Equipment Failure (such as the 2022 Derecho, which became the 6th costliest natural disaster in Canada's history and for which Hydro Ottawa did not seek a Z factor mechanism to recover costs from). The variability of in-service assets to plan and the impact on opening ratebase are being prudently reviewed as part of this application process.

The embedded stretch factor is the product of the real savings built into the 2026-2030 capital plan. They are committed dollars to reduce the capital cost of assets that would otherwise incur a quantifiable expense of an additional $35M to rate payers. As a result of the built-in savings, customers will incur $6.7M less through rates over the 2026-2030 period. Please see Table 4 of Schedule 1-3-1 - Rate Setting Framework for the revenue requirement savings. At the time of Hydro Ottawa's next rebasing application, a review of the opening rate base will occur, however the savings experienced as a result of the built-in stretch during the 2026-2030 rate period will remain.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

1.0-VECC-6

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 1

QUESTION(S):

a) Please provide the costs of the third party customer engagement surveys completed since the last cost of service application including: Utility Pulse Customer Satisfaction Survey(s); Innovative Research Group (both Satisfaction and customer engagement related directly to the 2026 CIR application).

RESPONSE(S):

a) Please see below for the annual costs of third party customer engagement surveys completed since Hydro Ottawa's last rebasing application. Table A includes:

- Utility Pulse - Customer Satisfaction surveys (Residential and Small Commercial)
- Utility Pulse - Customer Satisfaction surveys (Large Commercial)
- Innovative Research - Customer Satisfaction surveys
- Innovative Research - Behind the Meter survey
- Innovative Research - 2026-2030 Customer Engagement Survey

Table A - 2021-2024 Third Party Customer Engagement Costs[1]

	2021	2022	2023	2024
Third Party Customer Engagement Survey Costs	**$ 38,100**	**$ 51,000**	**$ 42,900**	**$ 302,300**

[1] In 2023 the price reflects low response rate.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

2.0-VECC-7

EVIDENCE REFERENCE:

Exhibit 2 Part 1, Tab 1, Schedule 1, Table 16, page 23 of 34

QUESTION(S):

a) For the projects shown in Table 16 (2021-2025 Overview of Significant In-Service Additions) please provide median and average variance as between planned and actual capital costs including all projects planned but not undertaken.

b) Please provide the same as in a) but removing all projects which were not undertake (i.e., projects listed as N/A)

RESPONSE(S):

a) Table A below provides the totals for planned capital cost, actual capital cost and total variance for significant in-service additions, along with the median and average variance for all projects included in Table 16 of Schedule 2-1-1 - Rate Base Overview.

1 **Table A - 2021-2025 Overview of Significant In-Service Additions ($'000 000s)**

Investment Category	Capital Program	Project	Planned In-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
General Plant	CCRA	Cambrian 28KV Substation	2021	$ 50.1	2021-2022	$ 44.6	$ (5.5)
General Plant	CCRA	Riverdale Switchgear Upgrade	2024-2025	$ 2.4	N/A	-	$ (2.4)
General Plant	CCRA	Piperville Station Capacity Upgrade-New East	2025	$ 6.1	N/A	-	$ (6.1)
General Plant	Customer Service	Elster EA-MS Upgrade	2021-2025	$ 1.6	2022	$ 0.4	$ (1.2)
General Plant	Operations Initiatives	AMI Program	2022	$ 1.6	N/A	-	$ (1.6)
General Plant	Customer Engagement Platform	MyAccount	N/A	-	2023-2025	$ 6.8	$ 6.8
General Plant	Enterprise Solutions	ERP Program	2025	$ 9.7	N/A	-	$ (9.7)
General Plant	Enterprise Solutions	Service Now	N/A	-	2022-2025	$ 2.7	$ 2.7
System Renewal	Stations and Buildings Infrastructure Renewal	Fisher AK Station Rebuild	2022-2024	$ 9.6	N/A	-	$ (9.6)
System Renewal	Stations and Buildings Infrastructure Renewal	Dagmar Voltage Conversion	2025	$ 6.0	N/A	-	$ (6.0)
System Renewal	Stations and Buildings Infrastructure Renewal	Bayswater Transformer Replacement	2021	$ 3.4	2021-2024	$ 5.0	$ 1.6
System Renewal	Stations and Buildings Infrastructure Renewal	Bell's Corners Station Rebuild	2021-2023	$ 10.3	2022-2024	$ 13.6	$ 3.3
System Renewal	Stations and Buildings Infrastructure Renewal	Overbrook TO Switchgear Replacement	2022-2025	$ 6.7	2021-2024	$ 9.3	$ 2.6
System Renewal	Stations and Buildings Infrastructure Renewal	Lincoln Heights P&C Renewal	2021-2022	$ 1.1	2021-2024	$ 2.3	$ 1.2
System Renewal	Stations and Buildings Infrastructure Renewal	Rideau Heights DS T1 Renewal	2024	$ 3.2	N/A	-	$ (3.2)

Investment Category	Capital Program	Project	Planned In-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
System Renewal	Stations and Buildings Infrastructure Renewal	Shillington AD Station Renewal	2025	$ 2.5	N/A	-	$ (2.5)
System Renewal	Metering Renewal	2.5EL to 3EL	2021-2025	$ 2.4	2021-2025	$ 1.1	$ (1.3)
System Renewal	Metering Renewal	TR Communications Update	2021-2025	$ 2.1	2021-2025	$ 1.8	$ (0.3)
System Renewal	Metering Renewal	SC Communications Update	2021-2022	$ 2.0	2022-2025	$ 2.2	$ 0.2
System Renewal	Metering Renewal	TR Service to 200A SC	2021-2025	$ 1.1	2021-2025	$ 1.0	$ (0.1)
System Renewal	Metering Renewal	REX 1 Upgrade	2021-2025	$ 5.0	2023-2025	$ 5.3	$ 0.3
System Service	Capacity Upgrades	Cambrian 28KV Substation	2022	$ 26.9	2021-2023	$ 25.6	$ (1.3)
System Service	Capacity Upgrades	Uplands MS Second Transformer	2021	$ 11.4	2021-2023	$ 14.7	$ 3.3
System Service	Capacity Upgrades	Riverdale Switchgear Upgrade	2024-2025	$ 11.8	2024-2025	$ 5.5	$ (6.3)
System Service	Capacity Upgrades	Limebank MTS 4th Transformer	2021-2022	$ 3.0	2021-2022	$ 2.8	$ (0.2)
System Service	Capacity Upgrades	Piperville Station Capacity Upgrade-New East	2025	$ 24.6	2024-2025	$ 14.7	$ (9.9)
System Service	Capacity Upgrades	New Mer Bleue Station	N/A	-	2025	$ 6.6	$ 6.6
System Service	Grid Technologies	Advanced Distribution Management System (ADMS)	2021-2025	$ 5.0	2025	$ 17.9	$ 12.9
System Service	Field Area Network	Field Area Network	2021-2025	$ 5.0	2023-2025	$ 1.0	$ (4.0)
Total				**$ 214.6**		**$ 184.9**	**$ (29.7)**
Median Variance							**$ (1.2)**
Average Variance							**$ (1.0)**

1

b) Table B below provides the same as in part a) but removes all projects which are listed as N/A in either the Planned In-Service Date column or the Actual In-Service Date column.

Table B - 2021-2025 Overview of Significant In-Service Additions- Excluding Projects Planned But Not Undertaken ($'000 000s)

Investment Category	Capital Program	Project	Planned In-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
General Plant	CCRA	Cambrian 28KV Substation	2021	$ 50.1	2021-2022	$ 44.6	$ (5.5)
General Plant	Customer Service	Elster EA-MS Upgrade	2021-2025	$ 1.6	2022	$ 0.4	$ (1.2)
System Renewal	Stations and Buildings Infrastructure Renewal	Bayswater Transformer Replacement	2021	$ 3.4	2021-2024	$ 5.0	$ 1.6
System Renewal	Stations and Buildings Infrastructure Renewal	Bell's Corners Station Rebuild	2021-2023	$ 10.3	2022-2024	$ 13.6	$ 3.3
System Renewal	Stations and Buildings Infrastructure Renewal	Overbrook TO Switchgear Replacement	2022-2025	$ 6.7	2021-2024	$ 9.3	$ 2.6
System Renewal	Stations and Buildings Infrastructure Renewal	Lincoln Heights P&C Renewal	2021-2022	$ 1.1	2021-2024	$ 2.3	$ 1.2
System Renewal	Metering Renewal	2.5EL to 3EL	2021-2025	$ 2.4	2021-2025	$ 1.1	$ (1.3)
System Renewal	Metering Renewal	TR Communications Update	2021-2025	$ 2.1	2021-2025	$ 1.8	$ (0.3)
System Renewal	Metering Renewal	SC Communications Update	2021-2022	$ 2.0	2022-2025	$ 2.2	$ 0.2
System Renewal	Metering Renewal	TR Service to 200A SC	2021-2025	$ 1.1	2021-2025	$ 1.0	$ (0.1)
System Renewal	Metering Renewal	REX 1 Upgrade	2021-2025	$ 5.0	2023-2025	$ 5.3	$ 0.3
System Service	Capacity Upgrades	Cambrian 28KV Substation	2022	$ 26.9	2021-2023	$ 25.6	$ (1.3)
System Service	Capacity Upgrades	Uplands MS Second Transformer	2021	$ 11.4	2021-2023	$ 14.7	$ 3.3
System Service	Capacity Upgrades	Riverdale Switchgear Upgrade	2024-2025	$ 11.8	2024-2025	$ 5.5	$ (6.3)
System Service	Capacity Upgrades	Limebank MTS 4th Transformer	2021-2022	$ 3.0	2021-2022	$ 2.8	$ (0.2)
System Service	Capacity Upgrades	Piperville Station Capacity	2025	$ 24.6	2024-2025	$ 14.7	$ (9.9)

Investment Category	Capital Program	Project	Planned In-Service Date	Planned Capital Cost	Actual In-Service Date	Actual Capital Cost	Cost Variance ($)
		Upgrade-New East					
System Service	Grid Technologies	Advanced Distribution Management System (ADMS)	2021-2025	$ 5.0	2025	$ 17.9	$ 12.9
System Service	Field Area Network	Field Area Network	2021-2025	$ 5.0	2023-2025	$ 1.0	$ (4.0)
Total				**$ 173.5**		**$ 168.6**	**$ (4.7)**
Median Variance							**$ (0.2)**
Average Variance							**$ (0.3)**

1

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

2.0-VECC-8

EVIDENCE REFERENCE:

Exhibit 2, Tab 7, Schedule 1, page 7

Table 6 – Loss from Retirement of Utility and Other Property ($'000s)

UsofA	Net (Gain)/Loss	Historical Years			Bridge Years		TOTAL
		2021	2022	2023	2024	2025	2021-2025
4362	OEB Approved	$ 389	$ 751	$ 323	$ 336	$ 445	$ 2,243
4362	Actual (gain)/loss	$ (202)	$ 1,234	$ (897)	$ (368)	$ (273)	$ (506)
1508	**Variance**	**$ (590)**	**$ 483**	**$ (1,220)**	**$ (704)**	**$ (718)**	**$ (2,749)**

Table 7 – Loss from Retirement of Utility and Other Property ($'000s)

Net (Gain)/Loss	Test Years					TOTAL
	2026	2027	2028	2029	2030	2026-2030
Forecast	$ 167	$ 636	$ 596	$ 609	$ 576	**$ 2,583**

QUESTION(S):

a) Leaving aside 2022, which HOL explains had increased losses as a result of the Derecho, the average retirements up to 2025 were $373,000. Post 2026 the average retirements are $604,000. What explains the much smaller amount of retirements in 2026 of $167,000?

RESPONSE(S):

a) The larger amounts in the post 2026 timeframe is related to the AMI 2.0 Metering Renewal Project, which starts in 2026 and ramps up in the 2027-2030 timeframe. See Table 22 in Schedule 2-5-7 - System Renewal Investments for details on meter unit replacements.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

2.0-VECC-9

EVIDENCE REFERENCE: .

Exhibit 2, Tab 5, Schedule 3, page 16

Table 7 - Distribution System Plan Implementation Progress

KPI	Target	2019	2020	2021	2022	2023
DSP Implementation Progress	100 %	84%	89%	92%	90%	75%

QUESTION(S):

a) Please clarify how the above-noted table is calculated and relates to Appendix 2-AB. For example, the above table shows that in 2023 only 75% of the DSP was achieved. However, for 2023 Appendix 2-AB shows a variance from plan for total capital expenditures of + 14.1% and 6.9% on a net (of contributions) basis. Please explain the difference.

RESPONSE(S):

a) DSP Implementation Progress tracking focuses on planned capital projects categorized as either System Renewal or System Service investments. This KPI excludes system access projects, general plant expenditures, and all emergency work. Table 7 - Distribution System Plan Implementation Progress in Schedule 2-5-3 - Performance Measurement for Continuous Improvement uses the following formula as outlined in Section 3.2.1 of the same Schedule:

$$DSP\ Progress\ = \frac{Actual\ SS + Actual\ SR\ Expenditures}{Budgeted\ SS + Budgeted\ SR\ Expenditures} \times\ 100$$

Through the DSP Implementation Progress KPI, System Service and System Renewal actuals are compared against the internal Board of Directors' approved budget for both Budgeted System Service and Budgeted System Renewal, excluding Emergency Renewal.

The OEB Appendix 2-AB - Capital Expenditure Summary includes all programs categorized under System Access, System Renewal, System Service, and General Plant. Actual expenditures are benchmarked against the OEB budget approved in the 2021-2025 Rate application. In 2023, System Renewal showed a variance of -0.8% and System Service a variance of -29.2% under Appendix 2-AB.

In essence, the DSP Implementation Progress KPI is a more specific measure of progress for certain types of capital projects, using an internal budget, while Appendix 2-AB provides a broader overview of all capital expenditures against a different, regulatory-approved budget. This explains why the 2023 DSP implementation was 75%, while Appendix 2-AB showed a variance from the plan of +14.1% for total capital expenditures.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

2.0-VECC-10

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 3, page 47-773

"Based on analyzing the reliability trends between 2019 and 2023, Hydro Ottawa has observed an overall increase in the annual outage duration aspect, despite a decrease in the number of customer interruptions and outage count (pg.66)"

QUESTION(S):

a) Given the proposed large increase in HOL's capital expenditures over the 2026-30 rate plan period, especially with respect to system renewal and service projects, why did HOL choose not to include in its proposal specific metrics aimed at minimizing both the frequency and duration of scheduled outages?

b) If the Board were to require HOL to set scheduled outage targets (number, number of customers impacted, number of customer hours impacted) what range of targets would HOL consider reasonable? Would a single target for the duration of the plan be appropriate or would yearly targets be better associated with the details of the proposed DSP?

RESPONSE(S):

a) Scheduled outages are intentional disconnections for reasons like customer requests (renovations), construction, maintenance (improving equipment life), vegetation management,

forced switching (repairing previous outages), sectionalizing (staged power restoration), moving large items, or emergency service requests. Hydro Ottawa doesn't include specific metrics to minimize scheduled outage frequency or duration due to their diverse nature and the priority of safety. While scheduled outage frequency decreased due to better planning, the number of customers affected and total interruption hours increased between 2019 and 2023. For further details on plans to mitigate the impact of scheduled outages, refer to Section 4.5.2 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement.

b) Hydro Ottawa does not recommend target setting for scheduled outages, given the underlying safety implications and diverse nature of scheduled outage categories, as noted in part (a) above.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

2.0-VECC-11

EVIDENCE REFERENCE:

Exhibit 2, Tab 5, Schedule 4, Attachment E, page 27

"On May 21, 2022 a historic derecho swept through Hydro Ottawa's service territory. This derecho was one of the most destructive storms in Canadian history with winds up to 190 km/h.1 The storm resulted in over 400 poles that needed to be replaced. In addition, approximately 180,000 customers lost power. Approximately 50 percent of these customers were without power for multiple days. Some customers were without power for over two weeks. The restoration efforts included utilization of 335 contractors2. The storm impacted the entire service territory with wind equivalent to either an EF1 (138-177 km/h) or EF2 (178-217 km/h)winds."

QUESTION(S):

a) Were the 400 poles replaced of a standard to withstand EF2 winds?

b) What is the premium per pole (or other transmission asset technology) that provides a guarantee of an asset not failing when confronted with 217km winds?

c) What analysis has HOL undertaken of the cost-benefit efficacy of investments into more resilient (and expensive) assets as compared to a better, more effective and quicker post storm restoration plan?

RESPONSE(S):

a) Hydro Ottawa did not undertake a study to review whether or not the replaced 400 poles were capable of withstanding EF2 winds (wind speeds of 180-240 km/h as per). Wooden utility poles built to Canadian Standards Association standards (CSA CSA-O15 Wood utility poles and reinforcing stubs) may or may not withstand EF2 winds depending on factors such as pole class and height, span length and conductor loading, guying and anchoring, and wind direction and impact from debris. The design standard, as required by O.Reg 22/04,[1]CSA C22.3 No. 1: Overhead Systems, is not based on EF2-type winds, but rather normal meteorological data, which typically range from 90-120 km/h winds in Canada.

Following the event, Hydro Ottawa enhanced its design standards to withstand stronger winds. For further information, please see response to interrogatory 2-Staff-36 part (a).

b) The premium per pole that guarantees an asset will not fail when confronted with 217 km/h winds is dependent on several factors and cannot be attributed to a single number. Some of these factors include, but are not limited to, pole class and height, span length, number of circuits on the pole, guying and anchoring, and the path of the pole line. Poles provided by manufacturers are built to CSA-O15 Wood utility poles and reinforcing stubs standards (please refer to part (a) of the response to interrogatory 2.0-VECC-11).

As an example of a premium for a pole class increase, if Hydro Ottawa were to increase the strength of a pole from a Western Red Cedar, height 65', Class H1, to a Western Red Cedar, height 65', Class H2, the premium would be approximately $675/pole. Other factors, as mentioned above, would need to be considered and would contribute to increasing the premium.

c) Hydro Ottawa engaged 1898 & Co. to conduct a thorough assessment and develop a Resilience Investment Business Case. This study evaluates the cost-benefit effectiveness of

[1] O.Reg. 22/04: Electrical Distribution Safety under Electricity Act, 1998, S.O. 1998, c. 15, Sched. A

investments in more resilient assets, with a particular focus on undergrounding existing overhead lines. Hydro Ottawa's analysis, informed by the 1898 & Co. study, directly compared the financial advantages of proactive investments in resilient assets against the expenses of reactive post-storm restoration. For further details on Hydro Ottawa's resilience assessment, refer to Section 5.2.2.4 of Schedule 2-5-4 - Asset Management Process.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

2.0-VECC-12

EVIDENCE REFERENCE:

Exhibit 2, Tab

Table 39 - Vehicles Required for Additional Headcount

Vehicle Type	# New Vehicles
Heavy Duty	14
Medium Duty	11
Light Duty	29
Other	1
TOTAL NEW VEHICLES	**55**

QUESTION(S):

a) Using the Table 1 at Exhibit 4, Tab 1, Schedule 3, page 5 or the same table as modified by VECC-37 integratory at Exhibit 4 below, please assign the vehicles by type to the new positions for 2026.

RESPONSE(S):

a) Using Table 1 in Schedule 4-1-3 - Workforce Staffing and Compensation, Table A below provides the distribution of vehicles by type to each of the new positions by Appendix 2-JC OM&A Programs.

Please note that while Table 1 in Schedule 4-1-3 - Workforce Staffing and Compensation includes the Bridge years 2024 and 2025, Table A below only includes the new position totals for 2026-2030. In addition, as noted in Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement, Section 3.1.2 Fleet Pooling, Hydro Ottawa will be expanding its vehicle pooling program to improve utilization. As such, Hydro Ottawa will purchase 21 fewer vehicles, reducing the total needed for additional headcount from 55 to 34 vehicles. This reduction, detailed at the bottom of Table A below, comprises 17 light-duty vehicles and 4 heavy-duty vehicles.

Table A - New Vehicles Required by Program 2026-2030[1]

Program	New Positions 2026-2030	Vehicle Type			
		Heavy Duty	Medium Duty	Light Duty	Other
Metering	5			8	
Engineering & Design	41				
Distribution Operations	64	14	11	21	1
Customer Billing	1				
Customer & Community Relations	1				
Information Management & Technology	5				
Safety, Environment & Business Continuity	5				
Human Resources	2				
Finance	3				
SUB-TOTAL	**127**	**14**	**11**	**29**	**1**
Reduction for Pooling		(4)		(17)	
TOTAL	**127**	**10**	**11**	**12**	**1**

[1] The new vehicles required reflect vehicles needed for the staffing also added in 2024-2025.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-13

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), pages 9-10 and 32 (of 40)
Exhibit 3, Attachment 3-1-1(C), Load Forecast Data-Customers Excel File

Preamble:
With respect to the Residential class, Attachment 3-1-1(B) states:
"The customer forecast is based on a monthly regression model that relates the number of customers to a blended economic variable, using both population and gross domestic product (GDP); the correlation between the number of customers and blended economic variable is extremely high at 0.99. This improved methodology is a change from the prior forecast and helps explain the historical changes in customer growth since 2020".

Attachment 3-1-1(C), Res_Custs Coef Tab sets out the variables used in the Residential customer count regression model, their coefficient values and t-stats as follows:

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	39154.421	3002.162	13.042	0.00%
mEcon.Cust	245697.987	2837.162	86.600	0.00%
MA(1)	1.816	0.079	22.917	0.00%
MA(2)	2.070	0.135	15.329	0.00%
MA(3)	1.353	0.135	9.991	0.00%
MA(4)	0.446	0.080	5.587	0.00%

Attachment 3-1-1(B) states:

"The number of residential customers has increased significantly over the last 3 years, driven by increases in population growth and a change in how multi-unit residential buildings are metered. Hydro Ottawa provided Itron data showing the annual reclassification from bulk meters to individual unit meters. Prior to 2019, many multi-unit residential buildings were bulk metered as one commercial account, this has since changed with some units being individually unit metered. This is occurring in the construction of new multi-unit buildings as well as retro fitting existing buildings." (page 9 of 40)

QUESTION(S):

a) Please provide: i) the historic and forecast monthly values used for population and GDP (including sources) and ii) a detailed explanation (along with supporting calculations) setting out the derivation of the monthly values for the blended economic variable (mEcon.Cust) as set out in the Res_Cust Data Tab.

b) Please explain the basis (i.e., what they represent, why they were included, what how the monthly values were determined and what they are) for each of the following variables used in the Residential customer count regression model as shown in the Exhibit 3-1-1(B), page 32: i) MA(1), ii) MA(2), iii) MA(3) and iv) MA(4).

c) The calculation of the predicted values in the Res_Custs BX Tab does not use the MA(1), MA(2), MA(3) and MA(4) explanatory variables (per the regression model). Please provide an excel file that sets out: i) the monthly values (January 2013 through December 2030) for each of the explanatory variables used in the Residential customer count regression model and ii) the calculation of the predicted monthly value based on these values and the coefficients estimated by the regression model.

d) How does the regression model and the resulting customer count forecast for 2026-2030 account for the recent changes in how multi-residential buildings are metered (per Exhibit 3-1-1(B), page 6 of 40).

RESPONSE(S):

a) The historical and forecasted values for population, GDP, and the blended economic variable are found in Attachment 3.0-VECC-13(A) - Historical and Forecast Values for Population, GDP and the Blended Economic Variable. The population and GDP values are from the Conference Board of Canada's September 2024 economic forecast for the Ottawa and Gatineau area. The blended economic variable is calculated using an 80% weight on population and 20% weight on GDP.

b) The MA terms are autoregression correction terms to address serial correlation inherent in customer forecast models; there is customer variation around the predicted line that is not directly related to the model variable. Serial correlation occurs when the predicted value in the current period is strongly correlated with the predicted value in the prior period; if customer counts were higher in the last period than predicted, then customer counts are likely to be higher than predicted in the current period. The MA terms have a short impact and have a small impact in 2025 and no impact by November 2025.

c) The impacts of the MA(1), MA(2), MA(3), and MA(4) variables are shown collectively in the 'ARMA' column of the BX Tab. The MA terms are not explanatory variables which have monthly historical and forecasted values like the other explanatory variables have. The software used to generate the forecast does not generate the individual contributions of each MA term to the predicted value.

d) The model includes actual historical customer count data from January 2013 through October 2024. The impact of changes in how multi- residential buildings are metered are embedded in the recent historical data. The resulting forecast for the remaining months of 2024 and beginning of 2025 was compared with known future unit meter conversions and multi unit buildings under construction.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-14

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), page 15 (of 40)
Exhibit 3, Attachment 3-1-1(C), Load Forecast Data-Customers Excel File

Preamble:
Attachment 3-1-1(B) states:
"Separate models are estimated for commercial customers. GS50 customers are driven by the number of residential customers. The correlation between GS50 customers and residential customers is 0.97. A simple linear trend model is used to forecast customers for the GS1500 rate class. The GS1000 and GS5000 customer forecasts are held constant at their October 2024 levels. Table 2-3 shows the commercial average annual customer forecast, excluding the impact of customer reclassification from commercial electrification and large loads."

Attachment 3-1-1(C), GS50_Custs Coef Tab sets out the variables used in the GS<50 customer count regression model, their coefficient values and t-stats as follows:

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	13990.563	237.171	58.989	0.00%
mFcstCal.I	0.035	0.001	45.773	0.00%
mBin.Yr24	-170.981	44.703	-3.825	0.02%
MA(1)	0.849	0.047	18.223	0.00%

Attachment 3-1-1(C), GS1500_Custs Coef Tab sets out the variables used in the GS1500 customer count model, their coefficient values and t-stats as follows:

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.661	0.081	8.204	0.000
Trend	0.003	0.014	0.202	0.840

Attachment 3-1-1(C), StLight_Custs Coef Tab sets out the variables used in the Street Lighting connection count model, their coefficient values and t-stats as follows:

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.847	0.089	9.496	0.000
Trend	0.007	0.022	0.341	0.734

QUESTION(S):

a) Please explain the basis (i.e., what they represent, why they were included, how the monthly values were determined) for each of the following variables used in the GS50 customer count regression model: i) mBinYr24 and ii) MA(1).

b) Please provide the 2013-2030 monthly values for the MA(1) variable used in the GS50 customer count equation, as they are not provided in the GS50_Custs Data Tab.

c) In the GS50_Custs BX Tab (column G) the determination of the predicted GS<50 customer counts use a variable identified as “ARMA”. Is this the same as the MA(1) variable used in the GS<50 customer count regression equation?

i. If not, please provide an excel file that sets out: i) the monthly values (January 2013 through December 2030) for each of the explanatory variables used in the GS<50 customer count regression model and ii) the calculation of the predicted monthly value based on these values and the coefficients estimated by the regression model.

d) Please explain the basis (i.e., what they represent, why they were included, how the monthly values were determined and what they are) for each of the following variables used in the GS1500 customer count model: i) Simple and ii) Trend.

e) Please provide an excel file that sets out: i) the monthly values (January 2013 through December 2030) for each of the explanatory variables used in the GS1500 customer count trend model and ii) the calculation of the predicted monthly forecast counts based on these values and the trend model coefficients.

f) Please explain the basis (i.e., what they represent, why they were included and how the monthly values were determined) for each of the following variables used in the Street Lighting connection count model: i) Simple and ii) Trend.

g) Please provide as excel schedule that set out the determination of the predicted 2013-2030 monthly connection counts for the Street Lighting customer class based on the monthly values for the explanatory variables and the regression equation coefficients.

h) Please explain why, for the GS1000 and GS5000 classes the forecasts for 2026-2030 were held constant at the October 2024 values.

RESPONSE(S):

a) The Yr24Plus is a binary variable. This variable takes on a value of zero for all months prior to January 2024 and a value of one for January 2024 through December 2030. The model then estimates a coefficient on the binary variable, in this case -170.9. The variable then contributes -170.9 to the overall predicted value starting in January 2024. This variable is needed because the GS<50 class experienced a significant slowdown in connection growth in 2024. From January to October 2024, on average only 2 new connections were added per

month. This is less than the 2018-2023 average of 12. Without the Yr24Plus binary variable, the model would have over predicted connections in 2024.

The MA terms are an autoregression correction term to address serial correlation found in the model.

b) The MA term is not an explanatory variable which has monthly historical and forecasted values like the other explanatory variables have. It is an error correction term. The impact of the MA term, its contribution to the predicted value, can be found in the ARMA column of the GS50_Custs BX Tab in Attachment 3-1-1(C) - 1. Load Forecast Data - Customers

c) In Attachment 3-1-1(C) - 1. Load Forecast Data - Customers the ARMA column is the impact of the MA(1) term.

d) The GS1500 customer model is based on an exponential smoothing model. Exponential smoothing is a time series model based on a weighted average of past observations with the weights decaying exponentially over time. The predicted value in any one period is a function of the past values. The “variables” referenced, “Simple” and “Trend” are constructed from the historical customer data series (Yt). I. The exponential smoothing model with a trend is shown below:

$$L_t = \alpha Y_t + (1 - \alpha)(L_{t-1} + b_{t-1})$$

$$b_t = \beta(L_t - L_{t-1}) + (1 - \beta) b_{t-1}$$

The α parameter is the calculated Simple coefficient and the β parameter is the estimated Trend coefficient. The coefficients are estimated using a non-linear solve method with the objective function of minimizing the sum of the squared errors.

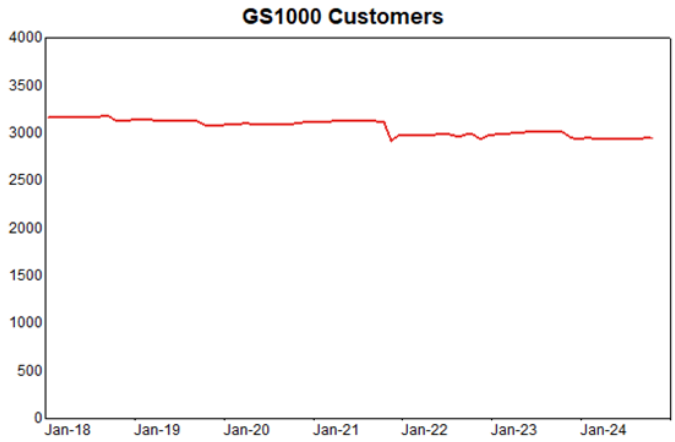
e) The GS1500 customer forecast uses an exponential smoothing model, there are no explanatory variables.

f) See response to part d).

g) The Street Lighting customer forecast uses an exponential smoothing model, there are no explanatory variables.

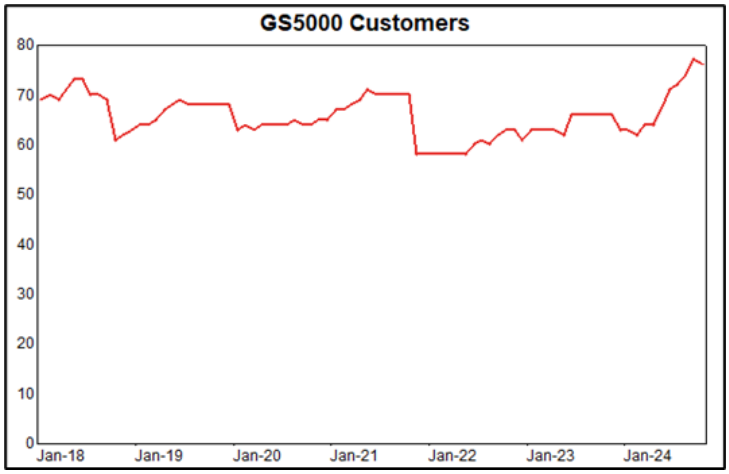
h) Over the past 5 years the GS1000 customer counts have remained flat, with the exception of reclassifications which occur each November[MR1] , seen below in Figure A. The forecast is held constant at the October 2024 value plus the estimated reclassifications. The flat forecast seems appropriate given the historical values.

Figure A - GS 50-1,000 kW Customer Count



The GS5000 class has a relatively small number of customers, 76 as of October 2024. Historically, this count has fluctuated but no known economic variable could explain the variation, see Figure B below. Because of this, the forecast is held constant at October 2024 value plus the estimated reclassifications.

Figure B - GS 1,500-4,999 kW Customer Count



INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-15

EVIDENCE REFERENCE:
Exhibit 3, page 5
Exhibit 3, Attachment 3-1-1(B), pages 16-17 and 24 (of 40)
Exhibit 3, Attachment 3-1-1(C), Load Forecast Data-Customers Excel File

Preamble:
Attachment 3-1-1(B) states:
"Generalized econometric models are estimated for Large Users, as well as Street Lighting, MU, and DCL. The Large User class is Hydro Ottawa's largest customers, the forecast assumes usage is held constant with adjustments made for anticipated large load requests and eDSM savings. The Street Lighting, MU, and DCL forecasts are not adjusted for eDSM savings." (page 16)

And

"Hydro Ottawa general service commercial rate class customers can be reclassified annually, based on their historical billing demand. This causes annual movements in the number of customers in each general service customer class, billing consumption (kWh) and billing demands (kW) between classes, with customers potentially moving up or down in terms of their demand. Hydro Ottawa provided Itron the actual annual reclassifications which included the most recent November 2024 reclassification. Customer counts, kWh, and billing kW were provided, showing which class the customers previously belonged to and which class they would fall under starting in November 2024. This data was used to move customer counts, kWh and kW demand from the customers' historical general service class to their current rate class in the forecast. The forecast also captures the impact of one Large User customer being disaggregated into multiple customer accounts in smaller commercial classes." (pages 16-17)

And

"Commercial electrification impacts customers in every commercial class from GS<50 to Large User. With electrification and significant increases in demand, these customers all move into the Large Use rate class." (page 24)

QUESTION(S):

a) Attachment 3-1-1(B) makes reference to the MU rate class. As the forecast 2026-2030 kWh values match, it appears that the MU rate class refers to the USL class (see Exhibit 3-1-1, page 4 and Exhibit 3-1-1(B), page 26). Please confirm that this is the case.

i. If not confirmed, please explain what customers the class represents and why this rate class is not included in the tables provide in Exhibit 3, page 5 which summarizes the customer/connection forecasts by customer class for 2026-2030.

b) Attachment 3-1-1(B) makes reference to the DCL rate class. As noted in Exhibit 3-1-1, page 8 (Footnote #7) the forecast does not include the Dry Core Transformer Charge. Please confirm that the DCL rate class refers to those customers subject to the Dry Core Transformer Charge and that the associated revenues are included in the Application as part of Other Revenues (as discussed in Exhibit 6).

c) Please explain how the customer/connection count 2026-2030 forecasts were developed for the Large Use, Street Lighting, Unmetered Scattered Load and Sentinel Lighting classes. For each class please provide: i) the basis and relevant statistics for any models used in developing the forecast, ii) the historical and forecast values for any explanatory variables used and iii) the calculation of the predicted values.

d) For each of the GS classes and the LU class please provide a schedule that sets out: i) the initial customer count forecast for 2026-2030 using the approaches described in Exhibit 3,

Attachment 3-1-1(B), page 15, ii) the adjustments made due to customer reclassification described in Attachment 3-1-1(B), pages 16-17, iii) the adjustments made due to one Large User customer being disaggregated into multiple customer accounts in smaller commercial classes described in Attachment 3-1-1(B), pages 16-17, iv) the adjustments made due to future electrification as described in Attachment 3-1-1(B), page 24 and v) the resulting final customer count forecast following these adjustments.

i. If this final customer count forecast by class does not match that set out in Exhibit 3, page 5, please explain why.

e) Please provide a schedule that provides a history of the annual re-classification of customers between the various GS classes and the Large Use class for the period 2013 to 2025 and, for each year, the month the reclassification occurred. For example, the 2013 values would represent the number of customers reclassified out of/into the different customer class in 2013 and the month the reclassification came into effect.

RESPONSE(S):

a) Confirmed, MU and USL are both referring to the Unmetered Scattered Loads class.

b) Confirmed.

c) The Large Use, Street Lighting and USL forecast methodology uses historical growth trends and adjusts them for known new connections. For details on forecast methodology, please refer to Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

d) Please see Attachment 3.0-VECC-15(A) - GS and LU Customer Count Forecasts with adjustments.

i. The values in Schedule 3-1-1 - Revenue Load and Customer Forecast, page 5 are an annual average based on a rolling monthly average.

e) Hydro Ottawa only has reclass data from 2015 onwards. The Historical GS reclasses are provided in Attachment 3.0-VECC-15(A) - GS and LU Customer Count Forecasts with adjustments.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-16

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B)

Preamble:
It is understood that at the time the load forecast was prepared by ITRON actual monthly customer/connection counts were only available up to October 2024.

QUESTION(S):

a) Please provide, in an excel file, the actual monthly customer/connection counts for each customer class from January 2013 to the most recent month where actual data is now available.

RESPONSE(S):

a) Please see Attachment 3.0-VECC-16(A) - 2013-2025 Monthly Customer Counts for the actual monthly customer counts for each customer class from January 2013 to June 2025.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-17

EVIDENCE REFERENCE:
Exhibit 3, Attachment 3-1-1(B), page 20 (of 40)
Exhibit 3, Attachment 3-1-1(C), Res_AvgUse Data Tab (column M)

Preamble:
The Application states:
"To capture the impact, select rate class models include a COVID impact variable. This variable is constructed using Google Mobility Report data for the residential, workplace and retail place types for Ontario. Google Mobility Report data tracks daily cell phone locations by place type compared to a pre-COVID baseline. The residential place type active increased while the workplace and retail decreased, this data correlates well to the actual changes in electric sales."

QUESTION(S):

a) Please provide the derivation of the historical values for the COVID impact variable (COVID.Residx) used in the Residential equation.

b) Please explain why, for the actual months of October 2022 through October 2024 the value for COVID.Residx remains constant at 0.186146257773965. One would have expected there to be some fluctuation in actual monthly values.

RESPONSE(S):

a) Attachment VECC-17(A) - COVID Impact Variable (COVID.Residx) derivation breakdown contains the raw Google Mobility data and the calculated monthly variables used in the residential and commercial models. The Google Mobility data is for the Ontario province. Google made this data available starting in mid-2020 and continued releasing updates through October 2022.

b) Google made this data available starting in mid-2020 and continued releasing updates through October 2022. Updated data was not available after November 2022. Through much of late spring and summer of 2022, the residential Google Mobility data had stabilized, not dropping back down to pre-COVID levels, indicating a new normal had been reached in terms of COVID's impact on work from home. Hydro Ottawa felt the most appropriate assumption for the forecast was to hold the residential Google Mobility index constant at the October 2022 level throughout the forecast period.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-18

EVIDENCE REFERENCE:
Exhibit 3, Attachment 3-1-1(B), page 7-11 (of 40)
Exhibit 3, Attachment 3-1-1(C), Res_AvgUse Data Tab

QUESTION(S):

a) Are the 2013 to 2023 Residential Average Use values set out in Table 2.1 (Exhibit 3-1-1(B), page 11) and the January 2013 to October 2024 Residential Average Use values set out in the Res_AvgUse Data Tab (column C) actual metered values or weather normalized values?

i. If weather normalized, how was each month's actual usage weather normalized?

ii. If actual metered values, how are weather variations captured in modeling so as to result in a weather normalized 2026-2030 forecast for the Residential class?

RESPONSE(S):

a) The values in Table 2.1 are not weather normalized, they are actual metered usage.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-19

EVIDENCE REFERENCE:
Exhibit 3, Attachment 3-1-1(B), pages 7-11 and 31 (of 40)
Exhibit 3, Attachment 3-1-1(C), Res_AvgUse Data Tab

Preamble:
The Application states:
"Average use is modeled using a Statistically Adjusted End-Use (SAE) modeling framework. This modeling framework integrates end-use saturation and efficiency trends that capture long-term, end-use, energy trends with monthly weather, number of days, and economic drivers that capture the expected utilization of the end-use stock. End-uses are mapped to heating (XHeat), cooling (XOther), and other uses (XOther)." (page 7 – emphasis added) Note: It is assumed that the application should read "cooling (XCool)".

QUESTION(S):

a) Please set out how the actual (January 2013-October 2024) values for the XHeat variable were determined for purposes of the Residential model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

b) Please set out how the forecast (November 2024-December 2030) values for the XHeat variable were determined for purposes of the Residential model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XHeat monthly forecast values). As part of the response please indicate how the increased saturation of heat pumps (per Figure 3-5, Exhibit 3-1-1(B), page 22) was factored into the monthly values.

c) Please set out how the actual (January 2013-October 2024) values for the XCool variable were determined for purposes of the Residential model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

d) Please set out how the forecast (November 2024-December 2030) values for the XCool variable were determined for purposes of the Residential model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XCool monthly forecast values). As part of the response please indicate how the increased saturation of heat pumps (per Figure 3-5, Exhibit 3-1-1(B), page 22) was factored into the monthly values.

e) Please set out how the actual (January 2013-October 2024) values for the XOther variable were determined for purposes of the Residential model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

f) Please set out how the forecast (November 2024-December 2030) values for the XOther variable were determined for purposes of the Residential model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XOther monthly forecast values).

g) Please explain why the Residential regression model (page 31) has no constant.

h) When assessing the inclusion of a potential explanatory variable in the various regression models used, at what value for the t-statistic does ITRON consider an explanatory variable to be statistically significant?

RESPONSE(S):

a) To deconstruct the XHeat variable into each component and replicate the calculations from Itron's proprietary software into Excel is a high-effort and time-intensive request, which Itron is unable to execute within the timelines for responding to interrogatories. With Itron's

support, Hydro Ottawa will be prepared to provide the requested information by way of undertaking at the Technical Conference.

b) Please see response to part a) regarding fully deconstructing the XHeat variable into each component and replicate the calculations in Excel.

Specific information about heat pump saturations and efficiencies are embedded in the calculation of the XHeat variable. Section 3.4 of Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast provides an explanation of how end-use saturations and efficiencies are incorporated into the SAE variables. Figure 3.5 shows the assumed heat pump saturation incorporated into the forecast. The heat pump saturations for heat and cooling are assumed to be the same.

c) See response to part a).

d) See response to part b).

e) See response to part a).

f) See response to part a).

g) The construction of the XOther variable includes the numbers of days per month, essentially allowing XOther to act as a constant. XOther can account for the fact that certain months should have more sales than other months simply due to the number of days in the month, all other things being equal. As a test, a constant can be added to the model, when this is done for the residential average use model the constant has a t-statistic of 0.144 and a P-Value of 88.56%. The constant is statistically insignificant.

h) The t-statistics alone is not the sole determining factor for deciding whether an explanatory variable is included or excluded from a model. A more holistic approach is taken where the

coefficient sign, t-statistic, overall model error, and adjusted R squared are considered. For example, a model variable with a t-statistic less than 1.96 would not immediately be removed from the model if the variable reduced the model error and/or increased the model fit. As a variable's t-stat approaches 1.44, or below, we would be more likely than not to remove the variable from the model.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-20

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), page 11 (of 40), Table 2-1
Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, Res_AvgUse Data Tab and Res_AvgUse BX Tab

QUESTION(S):

a) Please demonstrate that the average annual customer use values (2018-2030) set out in Table 2-1 are consistent with the monthly average use values reported in the Res_AvgUse Data Tab and Res_AvgUse BX Tab.

RESPONSE(S):

a) The summation of the monthly values reported in the Res_AvgUse Data Tab and Res_AvgUse BX Tab will not be identical to the annual average use values shown in Table 2-1 for two reasons. The first reason is a small mathematical difference in how the average use is calculated. The annual average use values shown in Table 2-1 are calculated as annual sales divided by average annual customers, this is not mathematically identical to the summation of the monthly average values. As a result, the 2018-2023 historical values may be different by 1-2 kWh.

The second reason for the difference is the forecasted values in the Res_AvgUse BX Tab are model outputs with CDM/eDSM held constant at October 2024 levels. Future CDM/eDSM is subtracted from the model generated forecast in post processing.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-21

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), pages 11-15 and 33 (of 40)
Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, GS50_Sales Data Tab and GS50_Sales BX Tab

QUESTION(S):

a) Did ITRON test the use of a COVID variable in the GS<50 regression model?

i. If yes, what were the results and why was a COVID variable not used?

ii. If not, please provide: i) an alternative version of the GS50 model that includes a COVID variable (i.e., coefficients and regression statistics) and ii) the predicted baseline forecast for 2026-2030 based on the resulting equation.

b) Are the January 2013 to October 2024 GS<50 Average Use values set out in the GS50_Sales Data Tab (column C) actual metered values or weather normalized values?

i. If weather normalized, how was each month's actual usage weather normalized?

ii. If actual metered values, how are weather variations captured in modeling so as to result in a weather normalized 2026-2030 forecast for the GS<50 class?

c) Please set out how the actual (January 2013-October 2024) values for the XHeat variable were determined for purposes of the GS<50 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

d) Please set out how the forecast (November 2024-December 2030) values for the XHeat variable were determined for purposes of the GS<50 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XHeat monthly forecast values.

e) Please set out how the actual (January 2013-October 2024) values for the XCool variable were determined for purposes of the GS<50 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

f) Please set out how the forecast (November 2024-December 2030) values for the XCool variable were determined for purposes of the GS<50 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XCool monthly forecast values).

g) Please set out how the actual (January 2013-October 2024) values for the XOther variable were determined for purposes of the GS<50 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

h) Please set out how the forecast (November 2024-December 2030) values for the XOther variable were determined for purposes of the GS<50 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XOther monthly forecast values).

i) Attachment 3-1-1(B) states at page 14 (of 40): "Table 2-2 shows the annual commercial sales baseline forecast for the SAE specified models. This forecast includes the impact of future eDSM but not electrification and large loads." For the GS<50 class please provide a schedule that sets out for the years 2025-2030: i) the baseline forecast per the SAE models (consistent with the GS50_Sales BX Tab (Column C)), ii) the adjustment for future eDSM and iii) the resulting forecast per Table 2-2.

RESPONSE(S):

a) Yes, Itron tested the use of a COVID variable in the GS <50 regression model.

i) Initially the commercial COVID variable was included in the model specification. With this specification, the CDM/eDSM variable t-statistic was -2.0, compared to -6.8 without the COVID variable included. When the COVID variable was included, it was statistically significant with a t-stat of -4.1. Attachment 3.0-VECC-21 B) - GS<50 Monthly Sales (with eDSM & Electrification Adjustments) provides the GS<50 MWh forecast with the COVID variable included. This forecast includes the impact of eDSM and electrification, comparable to the forecast shown in Table 1-1 of the Itron report.

ii) See response to i)

b) The values are not weather normalized, they are actual metered sales. The values are total GS<50 class sales in MWh, not average use.

i) See response to b)

ii) The model is estimated using actual metered sales and actual monthly heating and cooling degree days through October 2024. From November 2024 through December 2030, normal heating and cooling degree days are used to generate the forecast.

c) To deconstruct the XHeat variable into each component and replicate the calculations from Itron's proprietary software into Excel is a high-effort and time-intensive request, which Itron is unable to execute within the timelines for responding to interrogatories. With Itron's support, Hydro Ottawa will be prepared to provide the requested information by way of undertaking at the Technical Conference.

d) See response to question c).

e) See response to question c).

f) See response to question c).

g) See response to question c).

h) See response to question c).

i) Table 2-2 includes the impact of eDSM, customer reclassification, and a single Large User customer being disaggregated into smaller commercial classes. Although the disaggregation does not impact the GS<50 class. Attachment 3.0-VECC-21(A) - GS<50 Sales Forecast (with eDSM & Reclass Adjustments) contains the model output predicted values on tab i. Tab ii contains the future eDSM and reclassification adjustments. Tab Table 2-2 shows the calculated totals consistent with Table 2-2 in Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-22

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), pages 11-15 and 35 (of 40)
Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, GS1000_Sales Data Tab and GS1000_Sales BX Tab

QUESTION(S):

a) Are the January 2013 to October 2024 GS50 Average Use values set out in the GS1000_Sales Data Tab (column C) actual metered values or weather normalized values?

i. If weather normalized, how was each month's actual usage weather normalized?

ii. If actual metered values, how are weather variations captured in modeling so as to result in a weather normalized 2026-2030 forecast for the GS1000 class?

b) Please set out how the actual (January 2013-October 2024) values for the XHeat variable were determined for purposes of the GS1000 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

c) Please set out how the forecast (November 2024-December 2030) values for the XHeat variable were determined for purposes of the GS1000 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XHeat monthly forecast values.

d) Please set out how the actual (January 2013-October 2024) values for the XCool variable were determined for purposes of the GS1000 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

e) Please set out how the forecast (November 2024-December 2030) values for the XCool variable were determined for purposes of the GS1000 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XCool monthly forecast values).

f) Please set out how the actual (January 2013-October 2024) values for the XOther variable were determined for purposes of the GS1000 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

g) Please set out how the forecast (November 2024-December 2030) values for the XOther variable were determined for purposes of the GS1000 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XOther monthly forecast values).

h) Please provide the derivation of the historical values for the COVID impact variable (COVID.Comidx) used in the GS1000 equation.

i) Please explain why, for the actual months of October 2022 through October 2024 the value for COVID.Comidx remains constant at 0.197448511631785. One would have expected there to be some fluctuation in actual monthly values.

j) Attachment 3-1-1(B) states at page 14 (of 40): "Table 2-2 shows the annual commercial sales baseline forecast for the SAE specified models. This forecast includes the impact of future eDSM but not electrification and large loads." For the GS1000 class please provide a schedule that sets out for the years 2025-2030: i) the baseline forecast per the SAE models (consistent with the GS1000_Sales BX Tab (Column C)), ii) the adjustment for future eDSM and iii) the resulting forecast per Table 2-2.

RESPONSE(S):

a) The values are not weather normalized, they are actual metered sales. The values are total GS<1000 class sales in MWh, not average use.

i) See response to a).

ii) The model is estimated using actual metered sales and actual monthly heating and cooling degree days through October 2024. From November 2024 through December 2030, normal heating and cooling degree days are used to generate the forecast.

b) To deconstruct the XHeat variable into each component and replicate the calculations from Itron's proprietary software into Excel is a high-effort and time-intensive request, which Itron is unable to execute within the timelines for responding to interrogatories. With Itron's support, Hydro Ottawa will be prepared to provide the requested information by way of undertaking at the Technical Conference.

c) See response to part b).

d) See response to part b).

e) See response to part b).

f) See response to part b).

g) See response to part b).

h) Attachment 3.0-VECC-22 (A) - Covid Impact Variable Derivation Breakdown contains the raw Google Mobility data and the calculated monthly variables used in the Residential and General Service models. The Google Mobility data is for the Ontario province. Google made this data available starting in mid-2020 and continued releasing updates through October 2022. The commercial index used in the GS1000 model is an average of the workplace and retail sector Google data.

i) Google made this data available starting in mid-2020 and continued releasing updates through October 2022. Updated data was not available after November 2022. Through much of late spring and summer of 2022 the workplace and retail Google Mobility data, like the residential, had stabilized, not rising back to pre-COVID levels. Indicating a new normal had been reached in terms of COVID's impact on where and how people were working. Itron felt the most appropriate assumption for the forecast was to hold the workplace and retail Google Mobility index constant at the October 2022 level throughout the forecast period.

j) Table 2-2 of Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast includes the impact of eDSM, customer reclassification, and a single Large User customer being disaggregated into smaller commercial classes. Please refer to Attachment 3.0-VECC-22(B) - GS<1000 Sales Forecast (with eDSM, Reclass and Disagg Adjustments), which contains the model output predicted values on tab 'i'. Tab 'ii' contains the future eDSM, reclassification adjustments, and disaggregation adjustments. Tab 'Table 2-2' shows the calculated totals consistent with Table 2-2 in Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-23

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), pages 11-15, 24 and 36 (of 40)
Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, GS1500_Sales Data Tab, GS1500_Sale Coef Tab and GS1500_Sales BX Tab

QUESTION(S):

a) Did ITRON test the use of a COVID variable in the GS1500 regression model?

i. If yes, what were the results and why was a COVID variable not used?

ii. If not, please provide: i) an alternative version of the GS1500 model that includes a COVID variable (i.e., coefficients and regression statistics) and ii) the predicted baseline forecast for 2026-2030 based on the resulting equation

b) Are the January 2013 to October 2024 GS1500 Average Use values set out in the GS1500_Sales Data Tab (column C) actual metered values or weather normalized values?

i. If weather normalized, how was each month's actual usage weather normalized?

ii. If actual metered values, how are weather variations captured in modeling so as to result in a weather normalized 2026-2030 forecast for the GS1500 class?

c) Please set out how the actual (January 2013-October 2024) values for the XHeat variable were determined for purposes of the GS1500 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

d) Please set out how the forecast (November 2024-December 2030) values for the XHeat variable were determined for purposes of the GS1500 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XHeat monthly forecast values.

e) Please set out how the actual (January 2013-October 2024) values for the XCool variable were determined for purposes of the GS1500 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

f) Please set out how the forecast (November 2024-December 2030) values for the XCool variable were determined for purposes of the GS1500 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XCool monthly forecast values).

g) Please set out how the actual (January 2013-October 2024) values for the XOther variable were determined for purposes of the GS1500 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

h) Please set out how the forecast (November 2024-December 2030) values for the XOther variable were determined for purposes of the GS1500 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XOther monthly forecast values).

i) Please describe the purpose of the AR(1) variable included in the GS1500 model, provide the monthly values for period January 2013 to October 2024 and explain how the monthly values were determined.

j) What is the difference, if any, between the AR(1) variable used in the estimation of the GS1500 model (per the GS1500_Sale Coef Tab) and the ARMA variable (as used in the calculation of column O of the GS1500_Sales BX Tab)?

i. Please provide the forecast November 2024 to December 2026 values for the AR(1) and ARMA variables.

k) Unlike the GS50 and GS1000 models, the GS1500 model does not include CDM as an explanatory variable. Please explain why as Table 3-1 (Exhibit 3-1-1(B), page 24) indicates that there were historical CDM savings for this class.

l) Attachment 3-1-1(B) states at page 14 (of 40): "Table 2-2 shows the annual commercial sales baseline forecast for the SAE specified models. This forecast includes the impact of future eDSM but not electrification and large loads." For the GS1500 class please provide a schedule that sets out for the years 2025-2030: i) the baseline forecast per the SAE models (consistent with the GS1500_Sales BX Tab (Column C)), ii) the adjustment for future eDSM and iii) the resulting forecast per Table 2-2.

RESPONSE(S):

a) Yes, Itron tested the use of a COVID variable in the GS1500 regression model.

i) Including the commercial COVID variable was tested but the variable was statistically insignificant with a t-stat of -0.51. The model output can be found in Attachment 3.0-VECC-23(A) - GS<1500 Monthly Sales Forecast (with eDSM and Electrification Adjustments). This forecast includes the impact of eDSM and electrification, comparable to the forecast shown in Table 1-1 of the Itron report.

ii) Not applicable - please see response (a).

b) The values are not weather normalized, they are actual metered sales. The values are total GS<1500 class sales in MWh, not average use.

i) Not applicable - please see response (b).

ii) The model is estimated using actual metered sales and actual monthly heating and cooling degree days through October 2024. From November 2024 through December 2030, normal heating and cooling degree days are used to generate the forecast.

c) To deconstruct the XHeat variable into each component and replicate the calculations from Itron's proprietary software into Excel is a high-effort and time-intensive request, which Itron is unable to execute within the timelines for responding to interrogatories. With Itron's support, Hydro Ottawa will be prepared to provide the requested information by way of undertaking at the Technical Conference.

d) Please see response to part (c).

e) Please see response to part (c).

f) Please see response to part (c).

g) Please see response to part (c).

h) Please see response to part (c).

i) The AR term, similar to the MA term, is used for correcting model serial correlation. The AR term is estimated from past predicted values; its impact is similar to adding a lagged dependent variable. The AR term incorporates the impact of prior monthly sales on current month sales.

Since the AR(1) is not an independent model input there are no historical values. The monthly impact of the AR term is shown in the ARMA column of GS1500_Sales BX Tab. The tab shows the AR(1) contribution to the predicted value.

j) The coefficient tab (Coef Tab) shows the estimated coefficient of the AR correction term. The BX Tab shows the contribution of the AR variable to the predicted value generated from the estimated AR term.

    i) The coefficient and predicted value of AR(1) term is calculated by the model. There are no associated independent inputs.

k) Initial model testing included a CDM variable, but the sign on the estimated coefficient was counterintuitive to our understanding of the relationship between CDM and sales. When included, the estimated coefficient on the CDM variable was 0.9, implying as CDM increases, sales also increase. We know that as CDM increases, sales should decrease, all other things being equal. Likely the CDM variable was capturing some other positive trend in the GS1500 sales. Because of this, the CDM variable was removed. Increment new CDM is then subtracted from the model results to account for future CDM.

l) Table 2-2 includes the impact of eDSM, customer reclassification, and a single Large User customer being disaggregated into smaller commercial classes. Attachment 3.0-VECC-23(B) - GS<1500 Sales Forecast (with eDSM, Reclass and Disagg Adjustments) contains the model output predicted values on tab i. Tab ii contains the future eDSM, reclassification adjustments, and disaggregation adjustments. Tab Table 2-2 shows the calculated totals consistent with Table 2-2 in Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-24

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), pages 11-15, 24 and 37 (of 40)

Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, GS5000_Sales Data Tab and GS5000_Sales BX Tab

QUESTION(S):

a) Are the January 2013 to October 2024 GS5000 Average Use values set out in the GS5000_Sales Data Tab (column C) actual metered values or weather normalized values?

i. If weather normalized, how was each month's actual usage weather normalized?

ii. If actual metered values, how are weather variations captured in modeling so as to result in a weather normalized 2026-2030 forecast for the GS5000 class?

b) Please set out how the actual (January 2013-October 2024) values for the XHeat variable were determined for purposes of the GS5000 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

c) Please set out how the forecast (November 2024-December 2030) values for the XHeat variable were determined for purposes of the GS5000 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XHeat monthly forecast values.

d) Please set out how the actual (January 2013-October 2024) values for the XCool variable were determined for purposes of the GS5000 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

e) Please set out how the forecast (November 2024-December 2030) values for the XCool variable were determined for purposes of the GS5000 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XCool monthly forecast values).

f) Please set out how the actual (January 2013-October 2024) values for the XOther variable were determined for purposes of the GS5000 model (i.e., the detailed calculation including values and sources for each of the inputs and how they were incorporated into the overall calculation).

g) Please set out how the forecast (November 2024-December 2030) values for the XOther variable were determined for purposes of the GS5000 model (i.e., the basis for and the forecast values used for each of the inputs used in calculating XOther monthly forecast values).

h) Unlike the GS50 and GS1000 models, the GS5000 model does not include CDM as an explanatory variable. Please explain why when Table 3-1 (Exhibit 3-1-1(B), page 24) indicates that there were historical CDM savings for this class.

i) The GS5000 model includes a trend variable. Please explain how the historical and forecast monthly values for this explanatory variable were determined.

j) Attachment 3-1-1(B) states at page 14 (of 40): "Table 2-2 shows the annual commercial sales baseline forecast for the SAE specified models. This forecast includes the impact of future eDSM but not electrification and large loads." For the GS5000 class please provide a schedule that sets out for the years 2025-2030: i) the baseline forecast per the SAE models (consistent with the GS5000_Sales BX Tab (Column C)), ii) the adjustment for future eDSM and iii) the resulting forecast per Table 2-2.

RESPONSE(S):

a) The values are not weather normalized, they are actual metered sales. The values are total GS<5000 class sales in MWh, not average use.

i) See response a)

ii) The model is estimated using actual metered sales and actual monthly heating and cooling degree days through October 2024. From November 2024 through December 2030, normal heating and cooling degree days are used to generate the forecast.

b) To deconstruct the XHeat variable into each component and replicate the calculations from Itron's proprietary software into Excel is a high-effort and time-intensive request, which Itron is unable to execute within the timelines for responding to interrogatories. With Itron's support, Hydro Ottawa will be prepared to provide the requested information by way of undertaking at the Technical Conference.

c) See response to part b).

d) See response to part b).

e) See response to part b).

f) See response to part b).

g) See response to part b).

h) Initial model testing included a CDM variable, but the magnitude of estimated coefficient, and the resulting forecast, was not consistent with historical trends. The resulting forecast

would be significantly lower. When included, the estimated coefficient on the CDM variable was -2.5. Typically, we would expect a CDM coefficient to have a negative coefficient somewhere in the range of -0.5 to around -1.0. Due to this, the CDM variable was removed. Increment new CDM is then subtracted from the model results to account for future CDM.

i) The linear trend explanatory variable calculated in Itron MetrixND software, the historical and forecasted values can be found on the Data Tab (column Q) of Attachment 3.0-VECC-24(A) - GS<5000 Sales Forecast (with eDSM, Reclass and Disagg Adjustments). The variable equals 0 in December of 2014 and increases or decreases by 0.8333 (1/12=0.8333) each month before and after December 2014, creating a monthly linear trend. The slope of this trend is then determined by the estimated coefficient when this variable is included in the GS500 sales model. The trend variable is statistically significant with a t-statistic of -3.5.

j) Table 2-2 of Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast includes the impact of eDSM, customer reclassification, and a single Large User customer being disaggregated into smaller commercial classes. Attachment 3.0-VECC-24(A) - GS<5000 Sales Forecast (with eDSM, Reclass and Disagg Adjustments) contains the model output predicted values on tab I. Tab ii contains the future eDSM, reclassification adjustments, and disaggregation adjustments. Tab Table 2-2 shows the calculated totals consistent with Table 2-2 in Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-25

EVIDENCE REFERENCE:
Exhibit 3, Attachment 3-1-1(B), pages 16 and 38 (of 40)
Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, GSLrg_Sales Data Tab and GSLrg_Sales BX Tab
Exhibit 3-1-1, page 8 (Table 5)

Preamble:
The Application states:
"Generalized econometric models are estimated for Large Users, as well as Street Lighting, MU, and DCL. The Large User class is Hydro Ottawa's largest customers, the forecast assumes usage is held constant with adjustments made for anticipated large load requests and eDSM savings."

QUESTION(S):

a) Did ITRON test the inclusion of a HDD-related explanatory variable for the Large User class model?

i. If yes, what were the results and why was it excluded?

ii. If not, please provide: i) an alternative version of the GSLrg model that includes an HDD-related variable (i.e., coefficients and regression statistics) and ii) the predicted baseline forecast for 2026-2030 based on the resulting equation

b) Please describe how the historical and forecast values for the "wgtCDD18GSLrg" variable were determined.

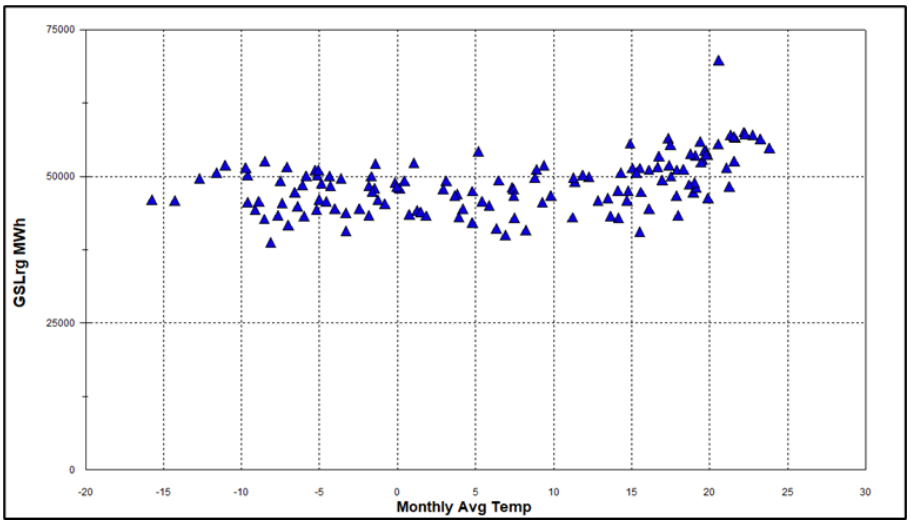
c) Unlike the GS50 and GS1000 models, the GSLrg model does not include CDM as an explanatory variable. Please explain why when Table 3-1 (Exhibit 3-1-1(B), page 24) indicates that there were historical CDM savings for this class.

d) The baseline 2026-2030 forecast values provided in Table 5 for the Large Use class do not match the sum of the predicted monthly values as set out in the GSLrg_Sales BX Tab (Column C) for the same year. Please explain why.

RESPONSE(S):

a) Initial modeling testing included an HDD variable with a base of 13 degrees. This variable had a coefficient of -0.58 and a t-stat of -0.59. The variable was statistically insignificant, and the negative coefficient does not make logical sense given the known relationship between weather and sales. A scatter plot below (Figure A) shows the relationship between GS5000 sales and average monthly temperature. There is no clear relationship on the left-hand side of the scatter, implying there is no relationship between sales and temperature when temperatures are below 13 degrees. For these reasons, the HDD variable was removed.

Figure A - Relationship Between GS 5,000 Sales and Average Monthly Temperature



b) The “wgtCDD18GSLrg” variable is the legacy of prior model iterations when data prior to January 2013 was included in the model estimation period. Prior to January 2013, the billed sales represented the sales over the billing period, which included the current month, prior month, and two months back. The weighted CDD or HDD variables combined three months of weather to create a weather variable which lined up the billing month sales, after January 2013 the variable was the current calendar month CDD/HDD. Beginning in January 2013, the metered sales reflected the calendar month which meant calendar month CDD and HDD variables could be used. The GS5000 model is estimated starting in January 2013, which means the wgtCDD18GSLrg variable is simply the calendar month CDD base 18 variable.

c) Historical savings for the GS Large User class were available and a CDM variable for the class was initially tested in the model specification. The variable had a coefficient of -0.5 and a t-stat of -1.5. Ultimately the decision was made to remove the CDM variable from the model. The incremental new CDM is subtracted from the forecasted model results to generate a CDM adjusted forecast.

d) GSLrg_Sales BX Tab (Column C) values are the model output and do not include the impact of incremental new CDM, the values in Table 5 of Schedule 3-1-1 - Revenue Load and Customer Forecast include CDM. CDM is subtracted from the model output to generate the baseline forecast.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-26

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), pages 16 (of 40)
Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, StLight_Sales Data Tab, StLight_Sales Coef Tab and StLight_Sales BX Tab
Exhibit 3, Attachment 3-1-1 (C)-2, Load Forecast Data – kWh, MU_Sales Data Tab, MU_Sales Coef Tab and MU_Sales BX Tab

Preamble:
The Application states:
"Generalized econometric models are estimated for Large Users, as well as Street Lighting, MU, and DCL. … The Street Lighting, MU, and DCL forecasts are not adjusted for eDSM savings."

QUESTION(S):

a) With respect to the Street Lighting model (StLight_Sales Coef Tab), please explain the basis for the "mBin.TrendVar" variable and provide the historical and forecast values.

b) With respect to the MU model (MU_Sales Coef Tab), please the rationale/basis for each of the variables used (i.e., "Simple", "Trend" and "Seasonal") and provide the historical and forecast values for the variable.

c) Please explain how the sales forecast for the Sentinel class was developed.

d) Please provide a table summarizing for each of the Street Lighting, USL and Sentinel classes: i) the actual/forecast annual sales (kWh) for 2013 to 2030, ii) the actual/forecast annual connections for 2013 to 2030 and iii) the average annual usage per connection for each of the years 2013-2030.

RESPONSE(S):

a) The linear trend variable in the Street Lighting model is the same variable used in the GS5000 model and explained above in 3.0-VECC -24 part i. The difference is the estimated coefficient of that trend variable and its impact on the model predicted value. The linear trend variable in the Street Lighting model is positive, capturing the increase in sales from additional lighting fixtures being installed.

b) The MU sales model uses an exponential smoothing model, similar to the GS 1500 customer model explained above in 3.0-VECC -14 d). The MU model also includes a seasonal component not found in the GS1500 customer model. Exponential smoothing is a time series model based on a weighted average of past observations with the weights decaying exponentially models. These models do not use explanatory variables; the forecasted values are a function of the historical dependent variable. The “variables” referenced, Simple, Trend, and Seasonal are parameters needed to estimate the model.

c) The Sentinel forecast was created using a trend analysis of historical data and then adjusted to account for expected decrease in units due to the Sentinel Light program no longer being offered and the existing lights continuing to be removed from service.

d) Please see Tables A, B and C below for Street Light, Unmetered Load and Sentinel Light annual sales, connections and kWh per connection.

Table A - Street Lighting Sales

Year	Sales (kWh)	Connections	Annual kWh per connection
2013	44,767,415	55,571	806
2014	44,363,900	55,531	799
2015	45,151,658	58,377	773
2016	45,206,290	58,706	770
2017	38,203,632	58,760	650
2018	31,723,370	59,740	531
2019	26,730,515	61,363	436
2020	22,495,936	62,222	362
2021	22,842,918	63,032	362
2022	22,059,316	63,545	347
2023	21,667,005	64,147	338
2024	21,721,725	64,382	337
2025	21,863,529	65,014	336
2026	21,961,791	65,912	333
2027	22,060,053	66,810	330
2028	22,158,315	67,708	327
2029	22,256,577	68,606	324
2030	22,354,839	69,504	322

Table B - Unmetered Scattered Load

Year	Sales (kWh)	Connections	Annual kWh per connection
2013	49,020	57	860
2014	50,344	57	883
2015	48,804	55	887
2016	48,064	62	775
2017	51,051	59	865
2018	48,433	57	850
2019	47,813	57	839
2020	46,478	54	861
2021	44,024	53	831
2022	44,760	52	861
2023	43,412	50	868
2024	42,468	49	867
2025	41,366	48	862
2026	40,631	47	864
2027	39,896	46	867
2028	39,161	45	870
2029	38,427	44	873
2030	37,692	43	877

Table C - Sentinel Lights

Year	Sales (kWh)	Connections	Annual kWh per connection
2013	49,020	57	860
2014	50,344	57	883
2015	48,804	55	887
2016	48,064	62	775
2017	51,051	59	865
2018	48,433	57	850
2019	47,813	57	839
2020	46,478	54	861
2021	44,024	53	831
2022	44,760	52	861
2023	43,412	50	868
2024	42,468	49	867
2025	41,366	48	862
2026	40,631	47	864
2027	39,896	46	867
2028	39,161	45	870
2029	38,427	44	873
2030	37,692	43	877

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-27

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), pages 16-17 and 24 (of 40)
Exhibit 3, Attachment 3-1-1(C), Load Forecast Data- Customers Excel File

Preamble:
Attachment 3-1-1(B) states:
"Hydro Ottawa general service commercial rate class customers can be reclassified annually, based on their historical billing demand. This causes annual movements in the number of customers in each general service customer class, billing consumption (kWh) and billing demands (kW) between classes, with customers potentially moving up or down in terms of their demand. Hydro Ottawa provided Itron the actual annual reclassifications which included the most recent November 2024 reclassification. Customer counts, kWh, and billing kW were provided, showing which class the customers previously belonged to and which class they would fall under starting in November 2024. This data was used to move customer counts, kWh and kW demand from the customers' historical general service class to their current rate class in the forecast. The forecast also captures the impact of one Large User customer being disaggregated into multiple customer accounts in smaller commercial classes." (pages 16-17 – emphasis added)

QUESTION(S):

a) For each of the GS classes and the LU class please provide a schedule that sets out: i) the initial customer class kWh baseline forecast for 2026-2030, ii) the adjustments made to each customer classes forecast 2026-2030 kWhs due to customer reclassification and the impact of one Large User customer being disaggregated into multiple customer accounts in smaller commercial

classes as described in Attachment 3-1-1(B), pages 16-17, and iii) the final resulting 2026-2030 kWh forecast for each class prior to the adjustments made for new DSM/CDM, electrification and large loads.

RESPONSE(S):

a) Refer to interrogatory responses to 3.0-VECC-21 (i), 3.0-VECC-22 (j), 3.0-VECC-23 (l), 3.0-VECC-24(j), and the accompanying Excel file provided to generate the numbers requested above for all GS classes.

b) Please refer to Attachment 3.0-VECC-27(A) - LU Sales Forecast (with eDSM and Reclass Adjustments) for the requested data for the LU class.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-28

EVIDENCE REFERENCE:
Exhibit 3-1-1, pages 15-18
Exhibit 3, Attachment 3-1-1(B), pages 24-25 (of 40) Statistics Canada

Preamble:
The Application states:
"However recent EV sales are not as high as anticipated, therefore major automakers are reconsidering (decreasing) their near term strategies on production capacity, model lineup, and marketing initiatives. Hydro Ottawa has incorporated these revised industry trends into the forecasting of EV adoptions." (page 16)

And

"Based on percentage of population, Hydro Ottawa has estimated 5.4% of total vehicles in Ontario reside in Hydro Ottawa's service territory. This percentage was applied to new LDEV registrations for years 2017 to 2023 in Ontario to estimate the total number of LDEV in Hydro Ottawa's territory. The 2021-2023 average annual growth trend of 0.8% was used to estimate the total LDEV for 2024-2030." (page 17)

And

"For Bridge and Test Years Hydro Ottawa apportioned the estimate of LDEVs to different rate classes by analyzing data from the Ministry of Transportation, Zero Emission Vehicle Infrastructure Program (ZEVIP) and customer data. Table 12 outlines the 2024-2030 LDEV MWh forecast." (page 18)

Attachment 3-1-1(B) states:

"These plans include electrifying light-duty transportation, heating/cooling and other reasons known/unknown to Hydro Ottawa. Hydro Ottawa provided Itron with incremental annual commercial electrification MWh and light-duty electric vehicle (EV) MWh estimates by class of customer. Monthly MWh series were generated and the cumulative MWh as of October 2024 were added to the respective classes."

Statistics Canada also reports new LDEV registrations by census metropolitan area (New motor vehicle registrations, quarterly, by geographic level)

QUESTION(S):

a) Please explain how Hydro Ottawa incorporated the revised industry trends (per page 16) into its forecast of EV adoption of 2024-2030.

b) Please explain (with supporting calculations) how the 2024-2030 forecast of total LDEVs in Table 11 was developed based on the average annual growth trend of 0.8%.

c) Please confirm that Table 11 represents the total number of LDEVs in the Ottawa area for each year and not the number of new LDEVs in the Ottawa area each year.

d) Please provide the breakdown of total LDEVs (per Table 11) by customer class for the years 2024-2030.

e) Please explain what customer data was used to help apportion the forecast LDEVs to the rate classes (per page 18).

f) Please explain (with supporting calculations) how the MWh values in Table 12 were derived based on the LDEV breakdown by customer class.

g) Please clarify whether Table 12 represents the total MWh associated with all LDEVs in the Ottawa area for each year or the incremental MWh due to new LDEV registrations in each year.

h) Please confirm that Table 3-3 (Exhibit 3-1-1(B)) represents the incremental LDEV load that was added to each customer class' baseline load forecast for 2025-2030.

i. If not confirmed, please provide a schedule setting out the incremental LDEV load that was added to each customer class' baseline load forecast for 2025-2030 and explain (with supporting calculations) how the values were derived.

i) As noted in the Preamble, Statistics Canada also reports new LDEV registrations by census metropolitan area. For the Ontario part of the Gatineau-Ottawa metropolitan area, total new LDEV registrations over the 2017-2023 period are reported as 12,487 (as opposed to the 9,344 estimate used by Hydro Ottawa). Why didn't Hydro Ottawa use the LDEV registrations reported by Statistics Canada for the Ontario part of the Gatineau-Ottawa metropolitan area as opposed to estimating the registrations based on Ottawa's percentage of the provincial population and total Ontario LDEV registrations?

RESPONSE(S):

a) Hydro Ottawa incorporated revised industry trends into its 2024-2030 EV adoption forecast by analyzing actual EV sales data and adjusting expectations based on recent market developments. For more detailed information and methodology, refer to section 9 of Schedule 3-1-1 - Revenue Load and Customer Forecast.

b) Please refer to interrogatory response 3-DRC-10. Note that Table 11 of Schedule 3-1-1 - Revenue Load and Customer Forecast was developed based on the average annual growth trend of 1.8%, not 0.8%.

c) Confirmed.

d) Table A provides the breakdown of forecasted LDEVs by customer class, from Table 11 in Schedule 3-1-1 - Revenue Load and Customer Forecast for the years 2024-2030.

Table A - LDEV Forecast by Rate Classification

Year	Residential	GS<50	GS 50-1,499	GS 1,500-4,999	GS > 5,000
2024	11,093	334	926	85	26
2025	14,398	434	1,202	110	34
2026	18,183	548	1,518	139	43
2027	22,393	674	1,869	171	53
2028	26,858	809	2,242	205	63
2029	31,627	952	2,640	242	75
2030	36,691	1,105	3,063	280	87

e) Please refer to the interrogatory response provided to 3-DRC-10.

f) Please refer to the interrogatory response provided to 3-DRC-10.

g) Table 12 of Schedule 3-1-1 - Revenue Load and Customer Forecast represents incremental MWh.

h) Confirmed.

i) The Statistics Canada data includes Gatineau and all of Ottawa. Hydro Ottawa's service territory is more limited, as residents of Gatineau are served by Hydro-Québec and some parts of Ottawa are served by Hydro One. By using a starting population point of Ottawa and removing specific areas served by Hydro One, Hydro Ottawa was able to isolate the specific areas within its service territory to get a more accurate percentage of LDEV share against total new LDEVs in Ontario.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-29

EVIDENCE REFERENCE:

Exhibit 3-1-1, pages 9 and 14-15
Exhibit 3, Attachment 3-1-1(B), pages 24-25 (of 40)
Exhibit 1-3-1, page 2

Preamble:
The Application states:
"Hydro Ottawa's revenue load forecast includes electrification and large load requests based on future customer initiatives aimed at decarbonization and electrification, as well as anticipated commercial and residential transportation electrification." (page 9)

And

"This surge in public sector electrification is evident in Hydro Ottawa's observed increase in incremental load demand from federal entities including Crown corporations and agencies projected for the 2024 to 2035 timeframe. Prior to specific large load requests, these customers are in the General Service (GS) > 50 to 4,999 kW class; after an extensive service upgrade request, these Customers are anticipated to be reclassified to the Large Use rate class. As noted above, this reclassification is observed in Tables 7 and 8 of the Electrification and Large Load energy and demand sales forecast." (page 14)

Attachment 3-1-1(B) states:

"Commercial electrification impacts customers in every commercial class from GS<50 to Large User. With electrification and significant increases in demand, these customers all move into the Large Use rate class."

QUESTION(S):

a) Exhibit 1-3-1 (page 2) sets out three different categories of large load requests: i) Signed Offer to Connect, ii) Submitted Load Summary Form and iii) Inquiries. Which categories has Hydro Ottawa included in its forecast commercial electrification impacts?

i. Please provide a revised version of Figure 1 (Exhibit 1-3-1, page 2) that reflects the load requests incorporated in the 2026-2030 load forecast.

b) Does the Large User electrification forecast set out in Table 3-4 (Exhibit 3-1-1(B), page 25 (of 40)) include not only the incremental load due to electrification but the "baseline" load for the associated customers that will now be Large Use load as a result of the customers' reclassification.

i. If confirmed, please indicate for each of the years 2024-2030 how much of the load shown in Table 3-4 is: i) additional load due to electrification versus ii) load reclassified to the Large Use class.

ii. If not confirmed, provide a schedule that sets out for each of the years 2024-2030: i) the additional load due to electrification, ii) the load reclassified to the Large Use class and iii) the total increase in Large Use load.

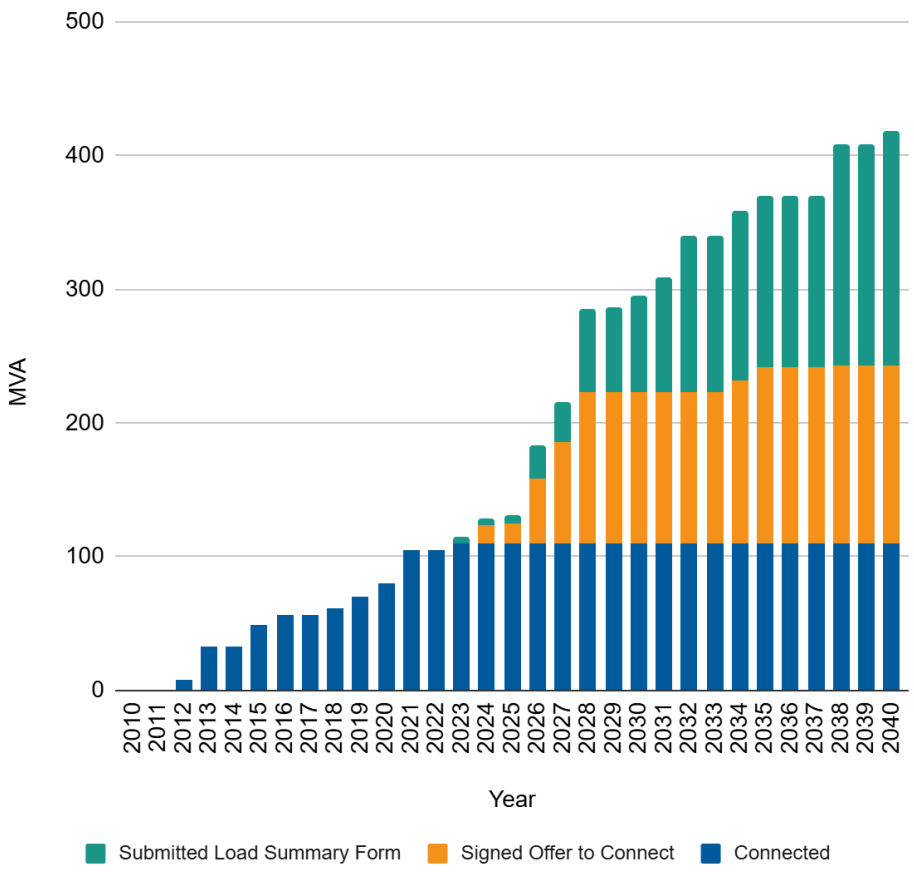
c) Please provide a schedule that breaks down the 2024-2030 Electrification And Large Load Energy Requests by Customer Class as set out in Table 7 (Exhibit 3-1-1, page 9) for each customer class as between: i) the impact due to LDEV load and ii) the impact due to commercial electrification.

RESPONSE(S):

a) Refer to part a) of Hydro Ottawa's response to interrogatory 2-CO-21 for a definition of each large load request category. Hydro Ottawa has considered projects in its planning forecast that have a Signed Offer to Connect and/or a Submitted Load Summary Form, as per the response in part c) of interrogatory 2-CO-21.

i) Please refer to Figure A below for a revised version of Figure 1 from Exhibit 1-3-1 - Rate Setting Framework that reflects the load requests incorporated in the 2026-2030 planning load forecast.

Figure A – Cumulative (MVA) Large Load Requests



b) Confirmed.

i) Refer to part (a) of the response to interrogatory 3.0-VECC-27.

c) Tables A and B show the breakdown of Table 7, from Schedule 3-1-1 - Revenue Load and Customer Forecast, showing both MWh for LDEV and MWh for Large Commercial Electrification.

Table A - LDEV MWh by Customer Class

	2024	2025	2026	2027	2028	2029	2030
Residential	2,210	25,607	42,226	61,389	83,095	107,515	134,648
GS > 50 kW	60	771	1,272	1,849	2,502	3,238	4,055
GS 50-1000KW	146	1,857	3,065	4,457	6,034	7,807	9,778
GS 1000-1500KW	22	281	460	668	902	1,169	1,463
GS 1500-5000 KW	15	196	323	469	635	821	1,029
Large User	5	60	100	145	196	254	318
Street Light	0	0	0	0	0	0	0
Sentinel	0	0	0	0	0	0	0
Standby	0	0	0	0	0	0	0
TOTAL	**2,458**	**28,772**	**47,445**	**68,976**	**93,364**	**120,803**	**151,290**

Table B - Large Commercial Electrification MWh

	2024	2025	2026	2027	2028	2029	2030
Residential	0	0	0	(0)	0	0	0
GS > 50 kW	0	0	(0)	0	0	0	0
GS 50-1000KW	0	(2)	(3)	(4)	(6)	(7)	(9)
GS 1000-1500KW	0	2	3	(8,577)	(16,610)	(16,610)	(16,608)
GS 1500-5000 KW	0	(0)	(7,932)	(7,932)	(7,932)	(7,932)	(7,932)
Large User	0	6,155	37,732	65,216	115,269	175,387	214,955
Street Light	0	0	0	0	0	0	0
Sentinel	0	0	0	0	0	0	0
Standby	0	0	0	0	0	0	0
TOTAL	**0**	**6,155**	**29,799**	**48,702**	**90,720**	**150,838**	**190,406**

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-30

EVIDENCE REFERENCE:
Exhibit 3-1-1, pages 19-21
Exhibit 3, Attachment 3-1-1(B), pages 23-24 IESO's 2021-2024 CDM Framework (dated December 15, 2022).
IESO 2023 Efficiency Report (2021-2024 Conservation and Demand Management Framework)

Preamble:
Attachment 3-1-1 states:
"Ontario's Minister of Energy and Electrification approved a new 12-year $10.9 billion eDSM framework that came into effect January 1, 2025 and takes place after the current 2021-2024 CDM Framework ends." (page 19)

And

"For 2025-2029 Hydro Ottawa estimated provincial wide annual energy efficiency savings of 2%, 3%, 4%, 5%, 5.5% respectively then 6% from 2030 through to 2035 across various programs with total demand savings of 3,000 MW as announced by the 33 Minister of Energy and Electrification. Hydro Ottawa's estimated portion of centrally administered programs' net energy and demand savings were based on IESO's Final Verified 2017 CDM Summary Report proportions for the years 2015 to 2017." (page 19)

And

"Schedule 9-1-5 - LRAM Variance Account provides detailed information on other assumptions related to achieved and/or projected energy savings in the period 2020 to 2025 by Hydro Ottawa

customers, as well as information for claimed historical and projected reductions in electricity consumption and demand. The historical energy savings were consistently used to create the Bridge and Test year revenue load forecast as well as amounts recorded into the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA). As noted above, energy savings for 2026-2030 used either the same assumptions or, where available, updated information from EMV reports." (page 20)

Attachment 3-1-1(B) states:
"Estimated historical CDM savings are directly incorporated into the estimated rate class sales forecast models as a separate model variable. In the residential average use model CDM is on a per customer basis and in the commercial models on a total MWh savings basis. These CDM variables are held constant at their October 2024 levels. Cumulative incremental new eDSM is then subtracted from the model results to arrive at the eDSM adjusted forecast."

And

"The CDM coefficient reflects the CDM savings not already captured in the SAE model structure. If none of the CDM savings were captured by the SAE specification, we would expect the coefficient on EDM to be -1.0. If all the CDM impacts were already captured by the model the coefficient would be close to 0 or statistically insignificant."

And

"Sales impact from future eDSM savings are derived by subtracting cumulative new eDSM savings as of October 2024 from the forecast model results. Table 3-2 shows the annual historical CDM and forecasted eDSM savings which are used in the forecast."

QUESTION(S):

a) With respect to Table 3-2 (Exhibit 3-1-1(B), page 24 of 40), please provide a schedule for each rate class that sets out for, each of the years shown (i.e., 2013-2030), the contribution to the year's cumulative saving made by CDM program savings in that year and in each of the preceding years. (For example, for 2030 the schedule for each class would show the savings in 2030 attributable to programs from each of the years 2013 to 2030)

i. Please also provide a similar schedule for the total cumulative CDM savings in each year (2013-2030).

ii. Please indicate and provide the sources for the savings used for the 2013-2019 CDM programs.

b) Please confirm that Schedule 9-1-5 includes CDM savings for the program years 2020-2023 (and not 2024 as indicated in the Application).

c) Please demonstrate that the savings from 2020-2023 programs used in the derivation of Table 3-2 are consistent with the values set out in Schedule 9-1-5.

i. With respect to Schedule 9-1-5, please indicate and provide the sources for the 2020-2023 program savings attributed to: i) the Conservation First Framework and ii) the Interim Framework.

d) Schedule 9-1-5 refers to savings from programs initiated as part of the "New Framework". Please indicate whether the "New Framework" refers to the IESO's 2021-2024 CDM Framework (dated December 15, 2022).

i. If yes, please provide a schedule that set outs how the savings shown in Schedule 9-1-5 (Persistence Report Tab) as being attributable to 2020-2023 programs were derived from the annual 2021-2023 savings targets in the IESO's 2021-2024 CDM Framework.

ii. If yes, what impact does the IESO's determination that savings from 2021-2023 programs only achieved 76% of planned savings (per the IESO's 2023 Efficiency Report, page 23) have on: i) the CDM saving values used by Hydro Ottawa from 2021-2023 programs, ii) the overall CDM savings set out in Table 3-2 and iii) Hydro Ottawa's 2026-2030 load forecast?

iii. If not, please indicate and provide the source for the New Framework savings. Also, please provide a schedule that set outs how the savings shown in Schedule 9-1-5 (Persistence Report Tab) as being attributable to 2021-2023 programs based on this New Framework.

e) It is noted that Schedule 9-1-5 (Persistence Report Tab) only provides persisting savings for individual 2020-2023 programs through to a year between 2024 to 2027, depending on the program. For those years (up to 2030) where no persisting savings from 2020-2023 programs are shown, what savings did Hydro Ottawa assume for purposes of preparing Table 3-2?

f) Please provide the derivation of the 2024-2030 savings from 2024 programs used in developing Table 3-2. As part of the response, please indicate whether the derivation relied on the savings set out in the IESO's 2021-2024 CDM Framework or some other source(s) and, if another source was used, please provide.

g) Please provide the following:

i. The values used by Hydro Ottawa for provincial energy savings for the period 2025-2030 from programs implemented in 2025-2030 and explain (with supporting calculations) how they were derived.

ii. The derivation of Hydro Ottawa's share of the provincial savings for the period 2025 to 2030 from programs implemented in 2025-2030 for purposes of developing Table 3-2.

RESPONSE(S):

a) Please refer to Attachment 1-Staff-11(A) - CDM Supporting Data.

b) Confirmed, the LRAMVA account proposed for disposition does not include forecast savings for 2024 CDM savings as applicable IESO EM&Vs have not been issued.

c) The CDM savings used for the LRAMVA claimed for 2020-2023 are from the Conservation First Framework (CFF) and 2021-2024 CDM Framework. As noted in Schedule 9-1-5 - Lost Revenue Adjustment Mechanism Variance Account the LRAM claim relates to 2021-2023 of both known and estimated CDM savings using IESO's Evaluation, Measurement, and Verification (EMV) reports for in-service activities, as well as the persistence savings from the CFF and Interim Framework programs for 2020 in-service activities. Please refer to Attachment 9-1-5(A) - LRAMVA Workform for kWh savings as well as Attachment 9-Staff-219(A) - HOL CDM&eSDM savings.

d) Confirmed the New Framework relates to the IESO's 2021-2024 CDM Framework.

i) Please refer to Attachment 9-Staff-219(A) - HOL CDM&eSDM saving for details that map the savings related to each framework.

ii) As Hydro Ottawa used the output of the Actual reported savings rather than planned savings the fact that the IESO only achieved 76% of the planned saving does not impact the calculation. Had the original saving estimate been left in Hydro Ottawa proposed 2021-2025 revenue load forecast the impact would have been on the variance between CDM saving embedded in the load forecast and what was actually achieved.

iii) Please see updated LRAMVA workform in response to interrogatory response 1-Staff-1 as Attachment 1-Staff-1(R) - OEB LRAMVA Workform as well as 9-Staff-219 that indicates the related energy efficiency framework. For the source material, refer to Section 3.2 of Schedule 9-1-5 - LRAM Variance Account.

e) The CDM savings as reported in Table 3-2 from Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast were used to determine the CDM variable for the revenue load forecast. The "sales impact from future eDSM savings [also reported in Table 3-2] are derived by subtracting cumulative new eDSM savings as of October 2024 from the forecast model results. Table 3-2 shows the annual historical CDM and forecasted eDSM savings which are used in the forecast."

f) The CDM savings for 2023 and 2024 were taken from the IESO's 2021-2024 CDM Framework - Program Plan[1] released on December 15, 2022.

g) Please refer to section 10 of Schedule 3-1-1 - Revenue Load and Customer Forecast.

[1] Independent Electricity System Operator,"2021-2024 Conservation and Demand Management Framework" https://www.ieso.ca/-/media/Files/SaveOnEnergy/2021-2024-CDM-Framework-Program-Plan.ashx

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-31

EVIDENCE REFERENCE:

Exhibit 3-1-1, pages 19-21
Exhibit 3, Attachment 3-1-1(B), pages 23-24
Exhibit 3, Attachment 3-1-1(C)-2. Load Forecast Data – kWh

Preamble:

Exhibit 3-1-1 states:
"Ontario's Minister of Energy and Electrification approved a new 12-year $10.9 billion eDSM framework that came into effect January 1, 2025 and takes place after the current 2021-2024 CDM Framework ends." (page 19)

And

"For 2025-2029 Hydro Ottawa estimated provincial wide annual energy efficiency savings of 2%, 3%, 4%, 5%, 5.5% respectively then 6% from 2030 through to 2035 across various programs with total demand savings of 3,000 MW as announced by the 33 Minister of Energy and Electrification. Hydro Ottawa's estimated portion of centrally administered programs' net energy and demand savings were based on IESO's Final Verified 2017 CDM Summary Report proportions for the years 2015 to 2017." (page 19)

And

"Schedule 9-1-5 - LRAM Variance Account provides detailed information on other assumptions related to achieved and/or projected energy savings in the period 2020 to 2025 by Hydro Ottawa customers, as well as information for claimed historical and projected reductions in electricity consumption and demand. The historical energy savings were consistently used to create the Bridge and Test year revenue load forecast as well as amounts recorded into the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA). As noted above, energy savings for 2026-2030 used either the same assumptions or, where available, updated information from EMV reports." (page 20)

Attachment 3-1-1(B) states:
"Estimated historical CDM savings are directly incorporated into the estimated rate class sales forecast models as a separate model variable. In the residential average use model CDM is on a per customer basis and in the commercial models on a total MWh savings basis. These CDM variables are held constant at their October 2024 levels. Cumulative incremental new eDSM is then subtracted from the model results to arrive at the eDSM adjusted forecast." (

And

"The CDM coefficient reflects the CDM savings not already captured in the SAE model structure. If none of the CDM savings were captured by the SAE specification, we would expect the coefficient on EDM to be -1.0. If all the CDM impacts were already captured by the model the coefficient would be close to 0 or statistically insignificant."

And

"Sales impact from future eDSM savings are derived by subtracting cumulative new eDSM savings as of October 2024 from the forecast model results. Table 3-2 shows the annual historical CDM and forecasted eDSM savings which are used in the forecast."

QUESTION(S):

a) For each of the Residential, GS50 and GS1000 classes please provide a schedule that sets out and explains the derivation of the values for the monthly CDM variable used in estimation of their respective regression models (per Exhibit 3-1-1(B), pages 31, 33 and 35 (of 40)).

i. Please demonstrate that, in each case, the derivation of the monthly values is consistent with the values shown in Table 3-2.

b) It is noted that for the Residential, GS50 and GS1000 classes the baseline kWh forecast the CDM variable is held constant at the October 2024 value in subsequent months (per Exhibit 3-1-1(C)-2. Load Forecast Data – kWh). Please explain why the post October 2024 values do not include any further loss in the persistence of these savings.

c) Please confirm that Table 13 (Exhibit 3-1-1, page 21) represents the future eDSM savings for each customer class that are subtracted from the class' forecast model results.

i. If confirmed, please provide a schedule for each customer class that sets out and explains the calculation of the future eDSM savings for the years 2025-2030 to be subtracted from the class' forecast model results (i.e., the values in Table 13)

ii. If not confirmed, please provide a schedule for each customer class that sets out the calculation of the future eDSM savings for the years 2025-2030 to be subtracted from the class' forecast model results.

d) For those customer classes where the "model" used to determine the baseline load forecast did not include CDM as an explanatory variable (i.e., GS1500, GS5000 and Large Use), since the CDM associated with each class increased over the 2013-2024 period (per Table 3-2), would it be reasonable to assume that the baseline forecast for 2025-2030 includes further increases in CDM savings?

i. If not, why not?

ii. If yes, how has this been accounted for in the determination of the adjustments made for future eDSM savings?

RESPONSE(S):

a) The impact of eDSM is held constant in 2025 to 2030. Please refer to interrogatory responses 3.0-VECC-21 i), 3.0-VECC-22 j), 3.0-VECC-23 l), 3.0-VECC-24 j), 3.0-VECC-27 and the accompanying MS Excel files provided to generate the schedule of monthly CDM variable used in estimation of their respective regression models all General Service classes.

b) The CDM variable is held constant at October 2024 levels, the resulting model forecast captures the impact of historical CDM but not new future eDSM. Cumulative incremental conservation savings for future eDSM are then subtracted from the forecast model results.

c) Confirmed.

i) See response in a).

d) The baseline forecasts shown in Table 2-2 of Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast include the impact of CDM. The outputs of the regression models, whether for classes with a CDM variable included or excluded, do not include the impact of future eDSM savings. The models either include an eDSM variable which are held constant, or they do not include an eDSM variable altogether. In either case, the baseline forecasts do not include the impact of future eDSM. Future incremental eDSM is then subtracted from the model forecasts to arrive at the eDSM-adjusted portion.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-32

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), page 26 (of 40) (Table 3-5)
Exhibit 3-1-1, page 4 (Table 1)

QUESTION(S):

a) With respect to Table 3-5, for each of the Residential, GS and Large Use customer classes please provide as schedule that sets out for the years 2024-2030: i) the baseline forecast kWhs per the relevant model, ii) the impact of customer reclassification (including and the impact of one Large User customer being disaggregated into multiple customer accounts in smaller commercial classes), iii) the impact of incremental LDEV loads, iv) the impact of electrification, v) the impact of new eDSM savings and vi) the proposed load forecast (i.e., sum of items (i) through (iv)).

i. If item (v) does not reconcile with Table 1, page 4 please explain why.

RESPONSE(S):

a) Refer to the below Table A for the annual incremental impact of LDEV and new eDSM savings to the Residential class.

Table A - Impact of LDEV and eDSM MWh for Residential Class

	2025	2026	2027	2028	2029	2030
eDSM	(11)	(33)	(56)	(79)	(103)	(127)
Electrification	14,075	16,619	19,163	21,706	24,420	27,133

For other rate classes, please refer to the following attachments:

- Attachment 3.0-VECC-21(A) - GS<50 Sales Forecast (with eDSM & Reclass Adjustments)
- Attachment 3.0-VECC-22(B) - GS<1000 Sales Forecast (with eDSM, Reclass and Disagg Adjustments)
- Attachment 3.0-VECC-23(A) - GS<1500 Monthly Sales Forecast (with eDSM and Electrification Adjustments)
- Attachment 3.0-VECC-23(B) - GS<1500 Sales Forecast (with eDSM, Reclass and Disagg Adjustments)
- Attachment 3.0-VECC-24(A) - GS<5000 Sales Forecast (with eDSM, Reclass and Disagg Adjustments)
- Attachment 3.0-VECC-27(A) - LU Sales Forecast (with eDSM and Reclass Adjustments)

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-33

EVIDENCE REFERENCE:
Exhibit 3-1-1, page 8 (Table 6) and 21 (Table 14)
Exhibit 3-1-1(B), page 16 (of 40)

Preamble:

Exhibit 3-1-1(B) states:
"Several commercial rate classes include a billing demand component. Billing demand is a measure of a customer's highest hourly demand over the billing period. Monthly billing demand regression models are estimated for each rate class. Demands are modeled as a function of monthly sales and monthly binary variables. The models are estimated with actuals from January 2018 to October 2024. The billing demand forecast includes the impact of eDSM savings but not electrification and large loads. Table 2-4 shows the annual rate class baseline billing demand forecast."

QUESTION(S):

a) In using the models to forecast the 2025-2030 billing demands for the relevant commercial rates did the forecast sales (kWh) used include the impact of new eDSM?

i. If not, how were the impacts of new eDSM on customer class billing demands determined for purposes of Table 14?

b) Was the forecast billing demand for the Large User class determined using the same approach as described for the commercial (i.e., GS) rates classes.

i. If not, how was the billing demand forecast for the Large User class determined?

c) Please confirm that Table 2-4 includes the impact of customer reclassification (including the impact of one Large User customer being disaggregated into multiple customer accounts in smaller commercial classes).

i. If not, please provide a revised version of Table 2-4 that includes the impact of customer reclassification.

d) For each of the demand billed commercial (GS) rate classes and the Large Use class please provide a schedule that sets out for each of the years 2018-2030: i) the actual/forecast kWh sales (where the forecast sales exclude electrification and large loads), ii) the actual/forecast billing kW (where the forecast amounts exclude the impact of electrification and large loads) and iii) the ratio of the item (ii) divided by item (i). Note: Both the kWh and the kW forecasts should include the impact of customer classification and future eDSM but exclude the impact of electrification and large loads.

e) With respect to Table 6 (Exhibit 3-1-1, page 8), please explain how the billing demand forecast for each of the Street Lighting, Sentinel Lighting and Standby classes was determined.

RESPONSE(S):

a) The forecasted sales (kWh) used to forecast billing demands included the impact of new eDSM.

i) See response a).

b) The same approach was used to forecast billing demands for all General Service (GS) and the Large User class.

c) Confirmed, Table 2-4 includes the impact of customer reclassification (including the impact of one Large User customer being disaggregated into multiple customer accounts in smaller commercial classes).

d) Please refer to Attachment 3.0-VECC-33(A) - GS and Large User Sales, Demand and Demand-to-Sales Ratios (2018-2030).

e) Street Lighting billing demands were forecasted using a similar approach to the GS and Large User classes, where demand is forecasted as a function of sales. The only difference being a 12-month moving average of sales is used in contrast to the actual monthly sales in the GS and Large User models.

Sentinel Lights and Standby billing demands were forecast based on analysis of Historical billed kW. Both were then adjusted; Sentinel Light to incorporate the forecast reduced connections and Standby to reflect a requested customer change to contracted demand (kW) amount.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

3.0-VECC-34

EVIDENCE REFERENCE:

Exhibit 3-1-1, pages 4, 15, 21

Preamble:
"actual EV hourly load profiles were used to forecast future impact of EVs on both customer and system peak demands." (page 15).

QUESTION(S):

a) How were the EV load profiles for each customer class determined (i.e., what "actual" load profile data was used to determine the profiles)?

b) Please provide the typical daily EV load profile used for each customer class. Note: If the load "daily" load profiles vary materially by weekday versus weekend or by month please provide the daily curves for each month and/or by weekday vs. weekend.

c) For each of the demand billed rate classes please provide a schedule that sets out for each of the years 2025-2030 the following: i) the forecast billing demand consistent with the model forecasts, ii) the adjustment to account for customer reclassification, ii) the adjustment to account for the impact of new eDSM, iii) the adjustment to account for incremental LDEV load, iv) the adjustment to account for electrification and large loads and v) the resulting forecast billing demand (i.e., the sum of items (i) through (iv)). per Table 2, page 4).

i. If Item (v) does not reconcile with the values in Table 2, page 4 please explain why.

RESPONSE(S):

a) The EV load profiles for each customer class were determined through analysis of EV chargers with separate meters. Hydro Ottawa identified a sample of individually metered residential chargers as well as fleet and public chargers in the Small Commercial and General Service rate classes and reviewed the hourly data for a twelve month period to determine the average load shape.

b) Figure A shows the Summer and Winter residential EV load shape. This is also displayed in Figures 4-2 and 4-3 of Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

Figure A - Summer and Winter Residential EV Load Shape

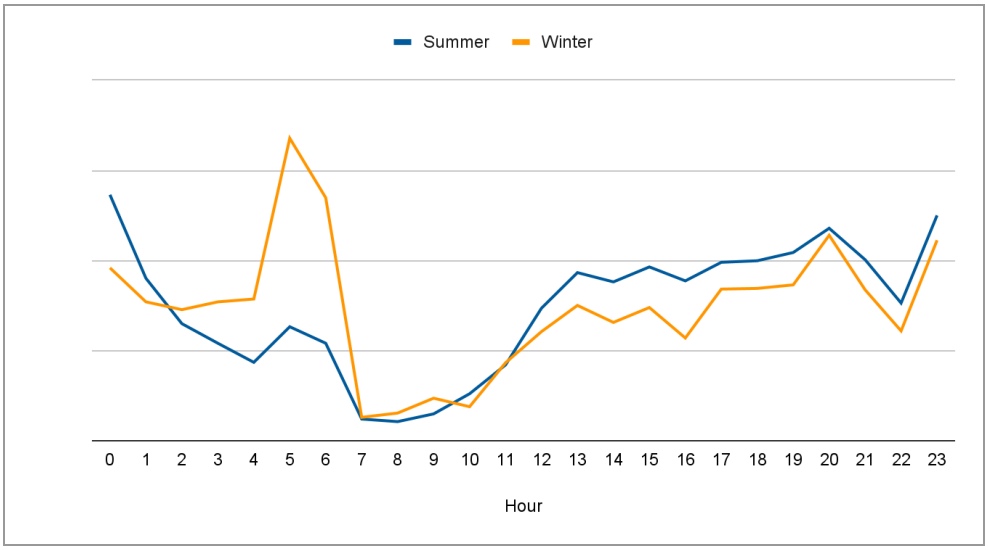
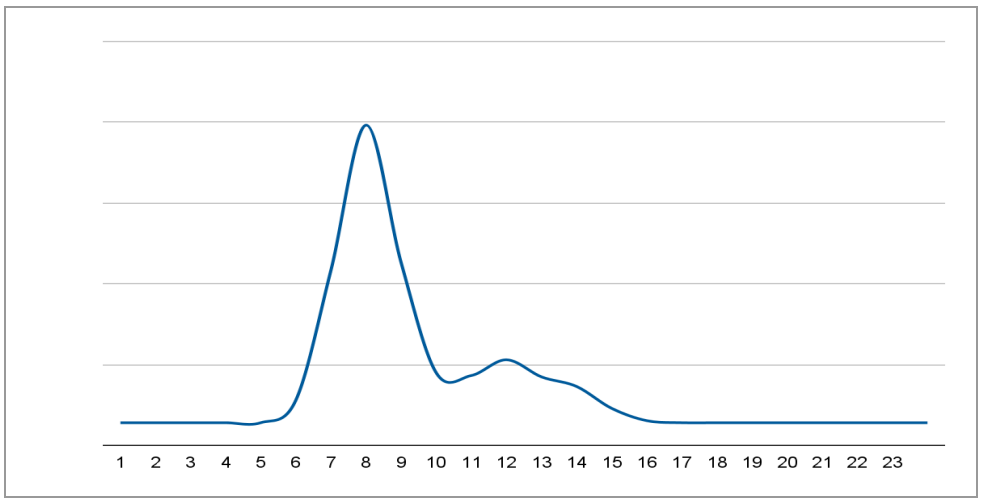


Figure B is the load shape used for commercial classes, based on the fleet charging load profile. The load shape had no seasonal differences and was applied for the full year.

Figure B - Full Year Commercial EV Load Shape



c) A full breakdown of the billing demand forecast is not possible within the given timeframe, and it was not required for this load forecast. Completing this request would necessitate decomposing the forecast into individual components, tracking the results, and then calculating the difference. In addition, refer to interrogatory response 9.0-VECC-72 for kW forecast for LDEV and large load electrification.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-35

EVIDENCE REFERENCE:

Exhibit 4 Appendix 2-JC

QUESTION(S):

a) Please provide a more detailed breakdown of OM&A programs by USoA account (i.e. as per the USofA Accounts included in Programs). Please include the account descriptor (e.g. Account 5045 refers to “Underground Distribution Lines and Feeders”)

RESPONSE(S):

a) Please refer to the Attachment 4.0-VECC-35(A) - O&A Programs by USofA account. The JC OM&A Programs are noted in Column A with the USofA accounts in column B. Note that there may be immaterial differences in the totals due to rounding.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-36

EVIDENCE REFERENCE:

Exhibit 4-2-5, page 2

QUESTION(S):

b) How were the annual LEAP contributions for each of the year 2021-2026 established?

c) How will the annual LEAP contributions for 2027-2030 be established?

RESPONSE(S):

Hydro Ottawa notes that there is no part a) to this question.

b) In establishing the LEAP contributions Hydro Ottawa complies with the greater of 0.12% of a distributor's OEB-approved distribution revenue requirement or $2,000 each year for LEAP contributions as per the Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, dated December 9, 2024, Updated May 7, 2025.

LEAP Contributions for the years 2021-2030 were established by using the Service Revenue Requirement from the Revenue Requirement Work Form in Schedule 6-1-1 - Revenue Requirement and Revenue Deficiency or Sufficiency in respective years multiplied by the LEAP percentage of 0.12%. Please refer to Schedule 4-2-5 - Low-Income Energy Assistance

Program. Note that both 2025 & 2026 figures from that Schedule were internal estimates prior to the OEB-approved distribution revenue figures being available. Please refer to the response to 4-Staff-175 for further details.

c) Hydro Ottawa will calculate annual LEAP contributions for 2027-2030 using the same methodology as described in part b). Specifically, Hydro Ottawa will establish the amount based on Approved Revenue Requirement during the rate term.

Hydro Ottawa will also continue to monitor and comply with any updated Chapter 2 Filing Guidelines and any new directions from the OEB regarding changes to LEAP funding in the future.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-37

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3, Table 1, page 5

Table 1 - New Positions by Appendix 2-JC OM&A Programs

	Bridge Years		Test Years					Total
	2024	2025	2026	2027	2028	2029	2030	
Metering	3		3	2				8
Engineering & Design	17		22	13	4		2	58
Distribution Operations[1]	22		43	21				86
Customer Billing			1					1
Customer & Community Relations			1					1
Information Management & Technology	2		5					7
Safety, Environment & Business Continuity	2		4		1			7
Human Resources	1		2					3
Finance	1			1	1	1		4
Regulatory Affairs	2							2
TOTAL	**50**		**81**	**37**	**6**	**1**	**2**	**177**

QUESTION(S):

a) Please provide a table, similar to Table 1 (New Positions by Appendix 2-JC OM&A Programs) for all positions in each year 2021 through 2030 but shows the total number of position (as compared to the incremental positions in the existing table). Please add any needed rows/categories so that the new table sums to the same total number of annual FTEs as shown in Appendix 2-K.

b) Is it actually the case that HOL has not and will not be hiring any persons in 2025. If so please explain why in light of the lengthy explanations as to the pressing need for additional employees set out in the evidence.

RESPONSE(S):

a) A breakdown for FTE by Appendix 2-JC OM&A programs is provided in Table C of the interrogatory response to 4-CCC-50, question b).

b) Hydro Ottawa increased the number of positions in 2024 by 50 due to the immediate needs of the company rather than waiting until 2025. In 2024 Hydro Ottawa was also recovering from the decreased focus on hiring due to the 84-day strike in 2023. As a result, 2025 was also used to stabilize workforce vacancies by filling vacant positions from internal movements (partially due to the new positions, please see Table 2 of Attachment B - Workforce Planning Strategy) and vacancies that arose through attrition (please see Table A of response to interrogatory 4.0-VECC-42 which shows 101 new hires in 2024). Due to the total number of new employees, training new staff was a major priority for 2025, which is an important step in the retention process. Lastly, in 2025 Hydro Ottawa is focusing on starting the recruitment process for the next new group of employees.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-38

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 4, page 2

Table 1 - On-going Regulatory Costs 2021-2026 ($000s)[3]

Regulatory Costs	Historical			Bridge		Test
	2021	2022	2023	2024	2025	2026
Compensation and Other	$ 977	$ 1,131	$ 1,047	$ 1,216	$ 1,318	$ 1,349
OEB Annual Assessment	$ 1,354	$ 1,558	$ 1,724	$ 1,930	$ 2,162	$ 2,164
Other Regulatory Memberships	$ 157	$ 156	$ 162	$ 168	$ 173	$ 175
Section 30 Costs	$ 63	$ 82	$ 79	$ 100	$ 90	$ 75
Total	**$ 2,551**	**$ 2,928**	**$ 3,011**	**$ 3,414**	**$ 3,743**	**$ 3,762**

QUESTION(S):

a) Please update the table to provide 2024's actual OEB annual assessment cost (if not already the case).

b) Please explain the nature of "other Regulatory Memberships".

c) Does the OEB bill on a semi-annual basis? If so please provide the actual 2025 amount billed to date.

d) How did HOL estimate the 2026 Section 30 costs?

RESPONSE(S):

a) Table A below has been updated with 2024 Historical Year actuals including the actual OEB annual assessment cost reported and paid in the 2024 calendar year (includes OEB's 2023-2024 Q4 assessment and 2024-2025 Q1 to Q3 assessments).

Table A - On-going Regulatory Costs 2021-2026 ($000s) with 2024 Actual

Regulatory Costs	Historical Years				Bridge Year	Test Year
	2021	2022	2023	2024	2025	2026
Compensation and Other	$ 977	$ 1,131	$ 1,047	$ 1,383	$ 1,318	$ 1,349
OEB Annual Assessment	$ 1,354	$ 1,558	$ 1,724	$ 1,990	$ 2,162	$ 2,164
Other Regulatory Memberships	$ 157	$ 156	$ 162	$ 170	$ 173	$ 175
Section 30 Costs	$ 63	$ 82	$ 79	$ 101	$ 90	$ 75
TOTAL	**$ 2,551**	**$ 2,928**	**$ 3,011**	**$ 3,643**	**$ 3,743**	**$ 3,762**

b) Other Regulatory Memberships represent the annual fee paid to the Electrical Safety Authority as required under the Electrical Distribution Safety Regulation, Ontario Regulation 22/04.

c) The OEB bills on a quarterly basis and sets a budget for their annual year which runs from April 1 to March 31 of the following year. The OEB typically completes a true-up from their estimated budget to their actual costs in the Q2 bill of the following yearly period if required. As described in the Annual OEB Cost Assessment letter, attached as Attachment 4-CCC-61(A) - OEB Letter re: Cost Assessment Fiscal Year 2025-2026, the OEB has not yet updated the invoiced amount for the 2025/2026 period. The OEB also indicated their current annual budget of $57.7M for 2024/2025 is estimated to increase to $70.1M. The allocation to the payer classes has also changed, however not as materially.

d) The actual amount billed for the periods January 1 to June 30, 2025 was $1,033,926. Please note Hydro Ottawa has also been billed for the period July 1, to September 30, 2025 in the amount of $516,963. These costs do not reflect the budget change indicated in the Annual Assessment Letter.

Based on the updated OEB budget estimate, Hydro Ottawa's quarterly amount for the 2025/2026 year should increase to approximately $630,000. Based on the information provided by the OEB, the estimate for the 2026 Test Year is too low, this is even without accounting for further adjustments for the 2026/2027 OEB Budget, which impacts 9 months of the 2026 Test Year.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-39

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 2

QUESTION(S):

a) If HOL is a member of the Electricity Distributor Association (EDA) please provide the annual membership fees for the 2021 to 2026 (test) period.

b) If HOL purchases insurance from MEARIE please provide the annual fees paid for the 2021 to 2026 (test) period.

RESPONSE(S):

a) Please see Table A below for annual membership fees paid by Hydro Ottawa to the EDA for the period 2021-2026.

Table A - Membership fee Paid to The EDA by Hydro Ottawa ($'000s)

Membership fee Paid to The EDA by Hydro Ottawa	Historical Years					Test Year
	2021	2022	2023	2024	2025	2026
Membership Fee	$123	$123	$129	$133	$137	$141

b) Please see Table B below for annual premiums paid by Hydro Ottawa to The MEARIE Group for the period 2021-2026.

Table B - 2021-2026 Premiums Paid to The MEARIE Group by Hydro Ottawa ($'000s)

Premiums Paid to The MEARIE Group by Hydro Ottawa	Historical Years				Bridge Year	Test Year
	2021	2022	2023	2024	2025	2026
Insurance Premiums	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-40

EVIDENCE REFERENCE:

Exhibit 4, Tab 2, Schedule 1

Table 3 – Summary of Shared Services Provided by Hydro Ottawa 2021-2026 ($'000s)

Provided By	Provided To	OEB Approved	Historical Years			Bridge Years		Test Year
		2021	2021	2022	2023	2024	2025	2026
Hydro Ottawa	Hydro Ottawa Holding Inc.	$1,487	$1,161	$1,386	$1,335	$1,421	$1,480	$1,583
Hydro Ottawa	Hydro Ottawa Capital Corporation	$1,602	$1,352	$1,662	$2,021	$1,801	$1,740	$1,421
Hydro Ottawa	Hydro Ottawa Energy Services Inc.	$1,712	$1,261	$1,298	$1,528	$1,676	$1,709	$1,777
Subtotal of Shared Services to Hydro Ottawa Affiliates		**$4,800**	**$3,775**	**$4,346**	**$4,884**	**$4,898**	**$4,929**	**$4,780**
Hydro Ottawa	Conservation First Framework Wind Down	$35	$64	$6	$3	$0	$0	$0
Total		**$4,835**	**$3,839**	**$4,352**	**$4,887**	**$4,898**	**$4,929**	**$4,780**

Table 4 – Summary of Shared Corporate Services Received by Hydro Ottawa 2021-2026 ($'000s)

Provided By	Provided To	OEB Approved[1]	Historical Years			Bridge Years		Test Year
		2021	2021	2022	2023	2024	2025	2026
Hydro Ottawa Holding Inc.	Hydro Ottawa	$3,816	$4,017	$5,018	$6,433	$6,893	$7,436	$7,712
Hydro Ottawa Holding Inc.	Conservation First Framework	$11	$14	$5	$7	$0	$0	$0
TOTAL		**$3,827**	**$4,031**	**$5,023**	**$6,439**	**$6,893**	**$7,436**	**$7,712**

QUESTION(S):

a) For each category, other than the Conservation First Framework, please provide the annualized the FTEs for each employed working for HOL.

b) For each category, other than the Conservation First Framework, please show the proportion of the costs that are labour related.

RESPONSE(S):

a) The annualized FTEs working for Hydro Ottawa are shown in Table A below. This represents the equivalent FTEs for Services Provided to Hydro Ottawa by Hydro Ottawa Holding Inc. Table A also shows the total FTEs at Hydro Ottawa Holding Inc. and the resulting percentage that has been allocated to Hydro Ottawa. Table A also includes the total number of employees at the holding company level and the associated percentage allocated to Hydro Ottawa.

Table A - 2021-2026 FTEs Working for Hydro Ottawa

Provided By	Provided To	Historical Years			Bridge Years		Test Year
		2021	2022	2023	2024	2025	2026
Hydro Ottawa Holding Inc.	Hydro Ottawa	17	20	22	22	23	23
Total number of FTEs in HOHI		31	32	34	36	38	38
% allocated to HOL		54%	61%	65%	61%	60%	61%

b) The proportion of costs that are labour related allocated to Hydro Ottawa from Hydro Ottawa Holding Inc. is shown in Table B below.

Table B - 2021-2026 Labour Related Costs Proportion ($'000s)

Provided By	Provided To	Historical Years			Bridge Years		Test Year
		2021	2022	2023	2024	2025	2026
Hydro Ottawa Holding Inc.	Hydro Ottawa	81%	75%	67%	63%	67%	67%

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-41

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3, Attachment B.

Table 1 - Annual Attrition Rate 2019-2024

Year	2019	2020	2021	2022	2023	2024
Attrition Rate	6.86%	7.19%	5.73%	7.39%	9.21%	5.61%

Table 2 - Internal Movements: 2019-2024

Year	2019	2020	2021	2022	2023	2024
Number of Internal Movements	15	17	26	37	47	62

QUESTION(S):

a) For positions which were not filled by internal movements what is the annual average and median time for a vacant position to be filled?

b) Please provide a table, similar to Table 1 (New Positions by Appendix 2-JC OM&A Programs) for all positions in each year 2021 through 2030 but shows the total number of position (as compared to the incremental positions shown in the existing table). Please add any needed rows/categories so that the new table sums to the same number of FTEs shown in Appendix 2-K.

RESPONSE(S):

a) Table A below displays the annual mean and median time-to-fill a position, for positions filled by external candidates. Time-to-fill is calculated as the number of calendar days between when a job requisition is created by the hiring manager to the date the signed offer letter is processed in Hydro Ottawa's Human Resources Information System (HRIS). This would include all tasks associated with the recruitment process from creation of a job posting, including translation, the required posting period, resume review and shortlisting of candidates, interviews, background/reference checking, compensation review, job offer creation and negotiation, as required, receipt of signed offer letter and processing in HRIS. The time-to-fill positions can vary dramatically based on the position and the required skill set and previous experience.

Table A - Mean and Median Time-To-Fill for Externally-Filled Positions, 2021-2024

Year	Mean Time-To-Fill (days)	Median Time-To-Fill (days)
2019	60	43
2020	55	24
2021	62	45
2022	51	30
2023[1]	86	60
2024	72	45

b) Please see the response to interrogatory 4-VECC-37.

[1]Time-to-fill in 2023 was impacted by the 84-day labour strike as recruitment was paused during this period.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

4.0-VECC-42

EVIDENCE REFERENCE:

Exhibit 4, Tab 1, Schedule 3

Table 10 – 2024-2026 - Reconciliation of Positions to FTEs in Appendix 2K

	Bridge Years		Test Year
	2024	**2025**	**2026**
Number of Full-Time Permanent Positions	667	667	748
Vacancy Assumption	10%	8%	8%
Vacancy Assumption translated into FTEs	(69)	(56)	(60)
Number of FTEs Sub total	**598**	**611**	**688**
Temps and Part Time	30	30	28
Number of FTEs (Appendix 2K)	**628**	**641**	**716**

QUESTION(S):

a) HOL's plan calls for the hiring of 81 full time positions in 2026. How many full time positions has HOL hired in each of the years 2021 through 2025?

b) From the time a position is approved by management for hiring what is the normal timeline for successful recruitment (e.g. job specification review, advertisement, short list selection, secondary interviews or selection, offer and arrival for work).

c) Do line managers (i.e. managers not from human resource) required to carry out interviews for employees in their departments?

d) Please provide the annual vacancy rate for 2021 to 2025 for full time positions (if not the same as the attrition rate shown 4-1-3 Attachment B page 10)

RESPONSE(S):

a) In each of the years 2021 through 2025 Hydro Ottawa has hired the following numbers of full time positions:

Table A - Number of Full Time Positions Hired, 2021-2025

Year	Number of FT Positions Hired
2021	37
2022	40
2023	36
2024	101
2025 (June 30th)	28

b) Please see response to interrogatory 4.0-VECC-41.

c) Yes, line managers are required to carry out interviews for employees in their departments.

d) The annual vacancy rate for 2021 to 2025 is provided in Table B below.

Table B - Annual Vacancy Rate for Full Time Positions, 2021-2025

Year	Vacancy Rate
2021	10%
2022	12%
2023	12%
2024	11%
2025 (June 30th)	9%

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

5.0-VECC-43

EVIDENCE REFERENCE:

Exhibit 5, Tab 1, Schedule 1, page 4 Exhibit 4, Tab 2, Schedule 1, page 6

Table 4 – Summary of Shared Corporate Services Received by Hydro Ottawa 2021-2026 ($'000s)

Provided By	Provided To	OEB Approved[1]	Historical Years			Bridge Years		Test Year
		2021	2021	2022	2023	2024	2025	2026
Hydro Ottawa Holding Inc.	Hydro Ottawa	$3,816	$4,017	$5,018	$6,433	$6,893	$7,436	$7,712
Hydro Ottawa Holding Inc.	Conservation First Framework	$11	$14	$5	$7	$0	$0	$0
TOTAL		**$3,827**	**$4,031**	**$5,023**	**$6,439**	**$6,893**	**$7,436**	**$7,712**

"Hydro Ottawa Capital Corporation issues long-term debt to support the financing requirements of Hydro Ottawa."

QUESTION(S):

a) Does Hydro Ottawa Capital Corporation apply any fee to the debt issuances? If yes please explain/show the costs for each Promissory Note shown in Appendix 2-OB for the year 2026.

b) Please explain the relationship (if any) between Hydro Ottawa Holding Inc. and Capital Corporation.

c) Specifically, please describe the position of any employees who undertake work for both Holdings, Capital and the regulated utility HOL.

d) Are any of the fees in 2026 charged by Holding Inc. in relation to financing debt services? If yes please describe these services.

e) For whom else does Hydro Ottawa Capital Corporation raise debt for?

f) What is the proportion of Capital Corporation debt is currently held by HOL?

RESPONSE(S):

a) Please see the response to interrogatory 5-Staff-178 part a).

b) Hydro Ottawa Capital Corporation (HOCC) is wholly owned by Hydro Ottawa Holding Inc.

c) Please refer to Schedule 4-2-1 - Shared Services and Corporate Cost Allocation for more information about the shared services and corporate cost allocation between Hydro Ottawa and its affiliated entities.

Hydro Ottawa understands that question c) pertains to the financing function only. The positions of Treasurer, and Manager, Corporate Financing are within Hydro Ottawa Holding Inc. but are responsible for managing the financing of Hydro Ottawa Holding Inc. and its affiliates, including HOCC and Hydro Ottawa. The Chief Financial Officer and Vice President, Finance of Hydro Ottawa Holding Inc. also provide oversight of the Treasury group, including any financing activities at HOCC and Hydro Ottawa.

d) No, there are no additional fees charged by Hydro Ottawa Holding Inc. to Hydro Ottawa Limited in connection with financing debt services, however, there are cost allocations from Hydro Ottawa Holding Inc. to Hydro Ottawa Limited related to shared corporate services. Employees within Hydro Ottawa Holding Inc., particularly the positions of Treasurer, and Manager, Corporate Financing, provide financing and debt management services to Hydro Ottawa, including but not limited to:

- Posting prudential support, the collateral that participants in Ontario's wholesale electricity market must provide to the Independent Electricity System Operator (IESO)
- Short-term liquidity management, including cash flow forecasting and short-term debt funding for Hydro Ottawa
- Maintaining credit facilities, including fulfilling ongoing compliance and reporting requirements
- Maintaining an investment grade credit rating for HOCC, to facilitate the periodic issuance of long-term debt in the Canadian capital markets
- Issuance of long-term debt instruments and ongoing compliance and reporting requirements
- Conducting investor relations to maintain strong working relationships with institutional fixed income investors, which helps Hydro Ottawa access long-term debt funding through HOCC at reasonable rates
- Managing ongoing compliance by Hydro Ottawa with the OEB's cost of capital guidance
- Monitoring Hydro Ottawa's ongoing exposure to foreign exchange risk and conduct foreign exchange transactions to fund foreign currency denominated procurement(s)
- Preparing short and long term financing budgets and forecasts
- Provide input as it relates to cost of capital and capital structure for Hydro Ottawa's periodic rate applications filed with the OEB

e) HOCC primarily raises debt for Hydro Ottawa Limited; please see response to part f) below. To a lesser extent HOCC also raises debt for Envari Holding Inc., Telecom Ottawa Holding Inc., and their unregulated affiliates.

f) As at December 31, 2024, 96.5% of HOCC's debt was accounted for by short-term debt and

long-term debt payable by Hydro Ottawa Limited to HOCC.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

5.0-VECC-44

EVIDENCE REFERENCE:

Attachment 6-3-1(A) – OEB Appendix 2-H

QUESTION(S):

a) Please provide the actual a revised version of Appendix 2-H that includes the actual interest rate for the two tranches of debt notes as forecast but raised prior to July 3 2025 (i.e. 3-Feb-25 and 2-Jul-25).

RESPONSE(S):

a) Please refer to Schedule 5-1-1 - Cost of Capital and Capital Structure, Attachment 5-1-1(M) Hydro Ottawa Limited $350.0M Promissory Note, for a copy of the promissory note issued by Hydro Ottawa to Hydro Ottawa Capital Corporation on February 3, 2025.

Please refer to Interrogatory Response 5-CCC-63, attachment 5-CCC-63(A) - Hydro Ottawa Limited $72.6M Promissory Note for a copy of the promissory note issued by Hydro Ottawa to Hydro Ottawa Capital Corporation on July 2, 2025.

Both promissory notes referenced above bear interest at a rate of 4.429%.

Hydro Ottawa understands that this interrogatory response is requesting a revised version of

Appendix 2-OB reflecting any changes to the forecast debt, which is attached as Appendix 2-OB of Attachment 1-Staff-1(A) - Chapter 2 Appendices in the response to interrogatory 1-Staff-1.

Please refer to Appendix 2-H of Attachment 1-Staff-1(A) - Chapter 2 Appendices in the response to interrogatory 1-Staff-1 for an updated version of Appendix 2-H.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

6.0-VECC-45

EVIDENCE REFERENCE:

Attachment 6-3-1(A) – OEB Appendix 2-H

QUESTION(S):

b) Please provide a revised version of Appendix 2-H that includes the 2024 actual values.

c) With respect to Account #4210, please provide the details supporting the 2023, 2024 (actual), 2025, 2026, 2027, 2028, 2029, and 2020 Pole Attachment Revenues (i.e. number of poles and annual rate used).

d) With respect to Account #4210, please provide the details supporting the 2023, 2024 (actual), 2025, 2026, 2027, 2028, 2029, and 2020 Duct Rental Revenues (i.e. Units billed and annual rate used per unit).

e) With respect to Account #4362, please explain how the forecast 2025-2030 values for each of the following were derived: i) Scrap Sales and Inventory Adjustments and ii) Net Book Value and Proceeds.

RESPONSE(S):

Hydro Ottawa notes there is no part a) to this question.

b) Please see Attachment 1-Staff-1(A) - Chapter 2 Appendices in the response to interrogatory 1-Staff-1 for a revised Appendix 2-H showing 2024 Historical.

c) Please see Table A below.

An assumption was made that this interrogatory had a typographical error in part c) when asking for '2020'. Hydro Ottawa has assumed this to be 2030, and provided this below.

Table A - USofA Account 4210 - Pole Attachment Revenues

Pole Attachment Revenues								
Year	Quantity - LDC	Quantity - Carriers	Quantity - Wireless	Rate - LDC	Rate - Carriers	Rate - Wireless	Other	TOTAL
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	(AxD) + (BxE) + (CxF) + G
2023 (Historical)	483	70,543	177	$90.60	$36.05	$373.32	$5,373	$2,658,286
2024 (Historical)	475	70,651	276	$90.60	$37.78	$387.88	$1,318	$2,820,603
2025 (Bridge)	483	70,555	397	$90.60	$39.14	$395.64	-	$2,962,352
2026 (Test)	483	70,555	497	$90.60	$39.14	$403.55	-	$3,005,847
2027 (Test)	483	70,555	597	$90.60	$39.14	$411.62	-	$3,051,020
2028 (Test)	483	70,555	697	$90.60	$39.14	$419.85	-	$3,097,918
2029 (Test)	483	70,555	797	$90.60	$39.14	$428.25	-	$3,146,598
2030 (Test)	483	70,555	897	$90.60	$39.14	$436.82	-	$3,197,110

d) Please refer to Table B below for the number of units, weighted average cost per unit, and the total revenue in relation to duct rental.

Table B - USofA Account 4210 - Duct Rental Revenues

	Historical		Bridge	Test	Test	Test	Test	Test
	2023	2024	2025	2026	2027	2028	2029	2030
Quantity	160,031	159,885	151,664	152,139	152,139	152,139	152,139	152,139
Weighted average rate	$8	$8	$8	$8	$9	$9	$9	$9
TOTAL REVENUE	**$ 1,215,974**	**$ 1,247,826**	**$ 1,233,197**	**$ 1,272,416**	**$ 1,309,536**	**$ 1,347,769**	**$ 1,387,149**	**$ 1,427,711**

e) With respect to USofA Account 4362:

i) Scrap Sales and Inventory Adjustments in 2025-2030 are based on past/current trends.

ii) Net Book Value and Proceeds are based on recent trending of actual disposals and proceeds received, normalized to exclude extraordinary or one-time events that are not expected to occur year-over-year. Additionally, for the Net Book Value forecasting, additional amounts were budgeted for 2026-2030 related to the expected meter replacements occurring under the Advanced Metering Infrastructure (AMI) 2.0 program, which is discussed in Schedule 2-5-7 - System Renewal Investments.

Appendix 2-OB reflecting any changes to the forecast debt, which is attached as Appendix 2-OB of Attachment 1-Staff-1(A) - Chapter 2 Appendices in the response to interrogatory 1-Staff-1.

Please refer to Appendix 2-H of Attachment 1-Staff-1(A) - Chapter 2 Appendices in the response to interrogatory 1-Staff-1 for an updated version of Appendix 2-H.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

6.0-VECC-46

EVIDENCE REFERENCE:

Exhibit 6-3-2, page 3-4

Preamble:
The Application states:
"Table 2 provides a summary of the forecasted revenue expected for SSCs for 2026-2030. Each SSC is forecasted based on the rate factored by the estimated volume."

QUESTION(S):

a) Please provide a schedule that for each of the specific services covered by the SCCs where Hydro Ottawa has proposed rates for 2026-2030 that sets out the actual billing volumes for 2023 and 2024 along with the forecast billing volumes for 2025-2030.

b) Please each of these services please also explain how Hydro Ottawa derived the forecast number of billing units for 2025-2030.

c) Do the OM&A costs included in the determination of Hydro Ottawa's proposed 2026-2030 distribution rates include any costs associated with providing the specific services for which Hydro Ottawa is proposing there be a separate charge in 2026-2030?

a. If yes, please identify such OM&A costs for each of the years.

RESPONSE(S):

a) Please see response to interrogatory 8-SEC-85 for 2023-2026 SSC volume. The volume for 2027 to 2030 mirrors that of 2026.

b) The number of billing units for the Bridge Year 2025 and 2026-2030 Test Years is based on historical trending. Please refer to Schedule 6-3-2 - Specific Service Charge Revenue Section 2.1 to Section 2.14 which provides explanations on how Hydro Ottawa forecast the units for each service charge (these are all contained within the 'variance analysis' portion of each section).

c) Yes, Hydro Ottawa's proposed 2026-2030 OM&A included in the service revenue requirement includes the costs associated with providing the specific services for which Hydro Ottawa is proposing there be a separate charge. The revenues from Specific Service Charges are not recorded net of costs. The SSC revenue collected is included in Other Revenue amounts which is an offset to the total Service Revenue requirement, this reduces the amount (base revenue requirement) to be recovered through distribution rates. Please refer to Schedule 6-1-1 - Revenue Requirement and Revenue Deficiency or Sufficiency and Schedule 6-3-2 - Specific Service Charge Revenue, Section 1 for further details.

    i) The specific service charge rates are based on recovering the cost to provide these services, please refer to Attachment 8-4-1(A) - Proposed and New Specific Service Charge Calculations for cost details. The total Specific Service revenues can be used as a proxy for total annual OM&A costs to provide these services.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

6.0-VECC-47

EVIDENCE REFERENCE:

Exhibit 6-3-1, pages 4-5
Attachment 6-3-1(A) – OEB Appendix 2-H

Preamble:
The Application states:
"In 2021, Hydro Ottawa's actual total Other Revenue was $1.6M lower than the OEB Approved amount, primarily in Other Income & Deductions. This variance was driven by a net loss in Services to Third Parties, attributed to increased costs and the non-billable activities. Layout volumes increased significantly, but the associated costs were not offset by revenue as many customers did not proceed with their projects."
Appendix 2-H shows that actual Costs and Expenses of Merchandising (USOA #4330) have exceeded Revenue from Merchandise (USOA #4315) in each of the years reported. Furthermore, Costs are forecasted to exceed revenues in each of the year 2024-2030.

QUESTION(S):

a) Please explain more fully why, in each of the years 2021-2023, Costs and Expenses of Merchandising (USOA #4330) have exceeded Revenue from Merchandise (USOA #4315).

b) Why is Hydro Ottawa forecasting that Costs and Expenses of Merchandising (USOA #4330) will continue to exceed Revenue from Merchandise (USOA #4315) over the period 2026-2030?

c) What changes would Hydro Ottawa have to make in either approach to providing or costing the related services in order either reduce or eliminate the variance where costs exceed revenues?

RESPONSE(S):

a) From 2021 to 2023, Hydro Ottawa's total Other Revenue consistently fell below OEB-approved amounts, primarily due to net losses in Services to Third Parties within the "Other Income & Deductions" category, attributed to both increased costs due to inflation and non-billable activities. Services to Third Parties contributed a $2.1M, $1.2M, and $1.4M loss in each year respectively. Since 2021, this loss has largely been attributable to the impact of the COVID-19 pandemic. Customer request volumes increased significantly, but the associated costs were not offset by revenue as many customers did not proceed with their projects, leading to the substantial net cost.

b) It is assumed the question has a typo and it is referring to USofA 4325 - Revenues from Merchandise. Hydro Ottawa forecasts that Costs and Expenses of Merchandising (USofA 4330) will continue to exceed Revenue from Merchandise (USofA 4325) from 2026 to 2030. This is primarily due to the introduction of a new Non-Wires Customer Solutions Program and a new non-billable activity: Residential Electrical Isolations/Re-energizations. This new service provides electrical work at no charge to the customer, aiming to promote safety and incentivize homeowners to pursue green projects. For more information on these incentives please refer to Section 2 in Schedule 6-3-5 - Other Income & Deductions.

c) Services to Third Parties will always have a variance where costs exceed revenues. This category includes non-billable activities and, as mentioned in response (b), Hydro Ottawa expects costs to increase by an additional $2.5 million per year due to the Non-Wires Customer Solution Program and the new Residential Electrical Isolations/Re-energizations, which provide electrical work at no charge to the customer. Outside of these budgeted losses, Hydro Ottawa

commits to managing rising costs through cost control objectives integrated into the utility's business planning processes.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

6.0-VECC-48

EVIDENCE REFERENCE:

Exhibit 6-3-3, page 1

Preamble:
The Application states:
"Hydro Ottawa projects a 3% increase in Late Payment Charge (LPC) for 2026 based on the historical year-over-year increase from 2021 to 2023. LPC revenues are estimated to increase 2.10% for the 2027-2030 period."

QUESTION(S):

a) What is the basis for the assumption that Late Payment Charge revenues will increase at 2.1%/annum for the 2027-2030 period?

RESPONSE(S):

a) As noted in Table 1 of Schedule 1-3-1 Rate Setting Framework, for other revenue, rates are proposed to be adjusted in years 2 to 5 (i.e., 2027-2030) based on inflation at a set rate of 2.1% for all four years (no adjustment based on the OEB approved inflation factor). While Late Payment Charge (LPC) revenues are not directly set by a fixed rate like other service charges, the forecast assumes a similar volume of late payments in each year from 2027–2030, with annual revenue growth applied at 2.1% to reflect the estimated inflation rate for the period. The

rationale for this proposal, as mentioned in Section 3.4 of the same schedule, is to simplify the process and avoid the need for annual adjustments to the rates throughout the rate term.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-49

EVIDENCE REFERENCE:

Exhibit 7-1-1, page 2

Preamble:
The Application states:
"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."

QUESTION(S):

a) Are there any other classes (e.g. Sentinel Lighting) where some/all of the associated customers are allocated a share of Miscellaneous Revenue via their primary accounts?

a. If yes, please identify such customer classes and the number of customers involved by primary account type.

RESPONSE(S):

a) Hydro Ottawa has no other classes whose members are billed separately and intermittently for contracted service, only if used, on the primary connection. Sentinel customers are billed for a load based on the use of the sentinel light, separate from their primary connection.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-50

EVIDENCE REFERENCE:

Exhibit 7-1-1, page 3
Exhibit 6-3-1(A) – OEB Appendix 2-H

Preamble:
The Application states:
"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."

And

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."

QUESTION(S):

a) Please provide a schedule that breaks down the actual and forecast (2021-2030) Costs and Expenses of Merchandising (USOA #4330) as between: i) expense related to Non-Wires solutions and ii) expenses incurred in relation to sale of merchandise.

b) Please explain why it is appropriate to exclude the Standby classes from the allocation.

RESPONSE(S):

a) The table below provides the requested breakdown. The non-wires expense for 2025 Bridge is the actual expense to July 30. Total expenses for the period 2025 - 2030 are forecast values.

Table A - Breakdown of of USofA 4330 - Costs and Expenses of Merchanding

USofA 4330 - Costs and Expenses of Merchandising				
Year		Non-Wires Solutions	Other Costs and Expenses	Total
2021	Historical	-	$ 8,570,242	$ 8,570,242
2022	Historical	-	$ 7,750,199	$ 7,750,199
2023	Historical	-	$ 6,984,646	$ 6,984,646
2024	Historical	-	$ 11,007,505	$ 11,007,505
2025	Bridge	-	$ 8,084,742	$ 8,084,742
2026	Test	$ 2,000,000	$ 8,573,180	$ 10,573,180
2027	Test	$ 2,000,000	$ 9,578,788	$ 11,578,788
2028	Test	$ 2,000,000	$ 10,065,902	$ 12,065,902
2029	Test	$ 2,000,000	$ 10,415,600	$ 12,415,600
2030	Test	$ 2,000,000	$ 10,755,306	$ 12,755,306

b) Standby customers are assessed a portion of the cost of non-wires solutions through their primary customer accounts in their respective General Service classes (GS 50-1,499 kW, GS 1,500-4,999 kW, and Large Use). The Standby agreement serves as a grid-based backup in the event that the customers' DER is not operating and should not be considered as a separate beneficiary of the non-wires development program.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-51

EVIDENCE REFERENCE:

Exhibit 7-1-1, pages 3-4
Exhibit 7-1-1(A) - 2026 Cost Allocation Model, Tab O2

Preamble:
The Application states:
"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.

QUESTION(S):

a) What is the impact on the Scenario 3 results for 2026 of including the cost of the Energy Transition, Customer Strategy and Innovation group recorded in USofA 5510 – Demonstrating and Selling Expense?

RESPONSE(S):

a) Note that Hydro Ottawa's response is based on the 2026 Cost Allocation Model updated for 2024 data and submitted under interrogatory response 1-Staff-1 as Attachment 1-Staff-1(H) - 2026 Cost Allocation Model.

Hydro Ottawa also notes that the costs recorded in USofA 5510 - Demonstrating and Selling Expense are customer-service related as described in Schedule 7-1-1 - Cost Allocation, Section 5, and are therefore why they have been included in this calculation.

Table A - Impacts of Inclusion of USofA 5510 below demonstrates the effect of adding USofA 5510 costs to the Customer Unit Cost per Month - Minimum System with PLCC Adjustment calculation. This particularly impacts the GS 50-1,499 kW, GS 1,500-4,999 kW, and Large Use customer classes, as they are the primary beneficiaries of services provided by the Energy Transition, Customer Strategy and Innovation group.

Table A - Impacts of Inclusion of USofA 5510

Customer Class	Customer Unit Cost per Month - Minimum System with PLCC Adjustment	
	with USofA 5510	without USofA 5510
Residential	$19.92	$19.91
GS <50	$26.89	$26.53
GS 50 to 1,499 kW	$84.53	$67.99
GS 1,500 to 4,999 kW	$464.59	$126.43
Large Use	$2,334.01	$258.11
Street Light	$6.69	$6.69
Sentinel	$19.66	$19.66
Unmetered Scattered Load	$9.17	$9.11
Standby Power GS 50 to 1,499 kW	$21.99	$22.00
Standby Power GS 1,500 to 4,999 kW	$22.00	$22.00
Standby Power Large Use	$22.00	$22.00

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-52

EVIDENCE REFERENCE:

Exhibit 7-1-1, pages 7-9

QUESTION(S):

a) Please provide the calculations supporting the proposed Billing and Collecting weighting factors for 2026.
b) Please provide the calculation supporting the proposed Meter Reading weighting factors for 2026.

RESPONSE(S):

a) Bill and Collect weighting factors have been calculated using 2026-2030 expense forecast data and customer counts by class. Each expense type was assessed for its impact on customer classes. Hydro Ottawa has identified six distinct patterns of customer utilization for the 18 major vendors providing Bill and Collect services, as depicted in Table A below.

Table A – Allocation Factors

Vendor Pattern	Residential	GS <50	GS 50-1499	GS 1500-4999	Large Use	Street Light	Standby	USL	Sentinel
1	1	1	1	1	1	1	1		
2	1	1							
3		1	1	1	1				
4	1	1	1	1	1	1	1	1	
5	1	1	1	1	1	1	1	1	1
6			1	1	1	1	1		

As the majority of large vendors have unique customer impact patterns, Hydro Ottawa has grouped them into two vendor groups. Group one vendors were allocated on the basis of patterns 1, 2, 3 and 6; and group two vendors were allocated on the basis of patterns 4 and 5. The average weightings for these two groups are presented in Table B.

Table B – Weighting Factors for Vendor Groups

Vendor Group	Residential	GS <50	GS 50-1499	GS 1500-4999	Large Use	Street Light	Standby	USL	Sentinel
1	1.0	1.0	1.0	1.0	1.0	1.0	1.1	0.0	0.0
2	1.0	1.3	3.6	3.6	3.6	3.8	5.0	2.2	0.7

b) The calculation of meter reading weighting factors employs the methodology described above and then aggregates the results to two groupings, smart meter customers and interval meter customers. Average calculated cost per customer for the interval group is compared to that of the smart meter grouping to derive the weighting factor for interval meter reading.

Table C – Meter Reading Weighting Factors

Meter Grouping	2026	2027	2028	2029	2030
Smart Meter Average cost per Customer	$ 3.29	$ 3.93	$ 4.60	$ 5.47	$ 6.57
Interval Meter Average cost per Customer	$ 17.84	$ 18.80	$ 19.77	$ 20.94	$ 22.35
Interval Meter Reading Weighting Factor	5.43	4.78	4.30	3.83	3.40

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-53

EVIDENCE REFERENCE:

Exhibit 7-1-1, pages 4 and 9-10
Attachment 7-1-1(A) - 2026 Cost Allocation Model, Tab O2

Preamble:
The Application states:
"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.."

QUESTION(S):

a) Please explain what the $26,953 in costs directly allocated to the Residential class for 2026 represent (per Tab O2, Row 226).

RESPONSE(S):

a) Hydro Ottawa records the $1.3M cost of the Energy Transition, Customer Strategy and Innovation Group in the directly allocated USofA 5510 - Demonstration and Selling Expense. This group is responsible for managing our Key Accounts customers, including consultations regarding our NWS programs and initiatives. The group consults with major customers in each

Customer Class, including major real estate developers that manage residential portfolios.

The costs of the group have been allocated on the basis of a detailed analysis of the work effort attributable to each of the major customers managed by the group over a one year period. The residential allocation of $26,953 in 2026 represents 2.04% of the total cost of the group.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-54

EVIDENCE REFERENCE:

Exhibit 7-1-1(G), pages 5-6
Exhibit 3-1-1(B), pages 31-38 (of 40)

Preamble: Exhibit 7-1-1(G) states:

"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). 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." (page 5)

And

"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." (page 5)

And

"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." (page 6)

The referenced pages from Exhibit 3-1-1(B) set out Itron's regression models for the Residential, GS and Large Use classes. Only the Large Use model explicitly includes a weather variable and, in that case, only a Cooling Degree Variable is included.

QUESTION(S):

a) Given that only the Large Use Model includes an independent weather variable (and then only for Cooling Degrees), please explain more fully how the models are run "with and without the HDD and CDD coefficients".

b) Please provide the Residential equation and explanatory variable values used to produce the 526.91 GWh value obtained by removing the HDD independent variable from the equation (per Attachment G, page 5).

c) Please confirm that the approach used by Hydro Ottawa assumes that for each customer class all hours in a given year/month have the same percent of actual load that is sensitive to HDD and the same percentage of actual load that is sensitive to CDD.

i. If not confirmed, please explain why.

ii. If confirmed, please explain why this is a reasonable assumption.

RESPONSE(S):

a) All Itron models, except the Large User model, use the variables XHeat and XCool to account for how heating and cooling (primarily influenced by HDD and CDD) affect energy load. To forecast load with and without these weather impacts, these variables are removed from the model. The Large User model only has a cooling coefficient. Consequently the demand profile process only considers the impact of cooling in weather normalizing the Large User class.

b) Please see table A.

Table A - Calculation of GWh Value for January 2023

Month	Itron Model Inputs			Predicted Average Load without Heat
	XHeatRes_AvgUse		Predicted Average Load	
	Value	Coefficient		
	A	B	B	D = C - (A*B)
January 2023	261.5	0.646	695.84	526.91

c) Hydro Ottawa confirms that for each customer class all hours in a given year/month have the same percent of actual load that is sensitive to HDD and the same percentage of actual load that is sensitive to CDD. This is an input assumption sourced from Itron's load profile forecast. Subsequent steps in the weather-normalization process refine this assumption at the hourly level to account for differential impacts of weather patterns and seasonality.

Hydro Ottawa notes that this is an accepted assumption that has been employed successfully in three other rate applications, as noted in the footnote on page 2 of Attachment 7-1-1(G) - 2026 Demand Allocators.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-55

EVIDENCE REFERENCE:

Exhibit 7-1-1(G), pages 8-9

QUESTION(S):

a) With respect to Table 3, please confirm that the HDH Weather Normalization factor for January 15, 2023 – Hour 19 (121.60%) is calculated as the ratio of (i) the HDD value for the hour based on normal weather over (ii) the actual HDD value for the hour.

i. If not confirmed, please explain how the value is calculated.

RESPONSE(S):

a) Confirmed. As described in Step 1: Determine Weather Profile of a Typical Year[1], actual HDH for each hour is compared to the ten-year average HDH for the similar ranked timeslot to arrive at the percentage indicated.

[1] Attachment Exhibit 7-1-1(G) - 2026 Demand Allocators, Page 3-4

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-56

EVIDENCE REFERENCE:

Exhibit 7-1-1(G), page 10
Exhibit 3-1-1, pages 14-15
Exhibit 2-5-4, pages 29-30

Preamble:
Exhibit 7-1-1(G) states:
"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.
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."
Exhibit 3-1-1 states:
"Hydro Ottawa's large commercial incremental load forecast incorporates known and anticipated system expansion requests from these key public sector entities. These requests encompass a range of initiatives, including the integration of EV charging infrastructure, the transition to electric heating and cooling systems, and electric industrial water heating." (pages 14-15)
And
"Hydro Ottawa developed the EV forecast integrated into both the revenue energy and demand forecasts using customer data as well as from Statistics Canada to forecast EV adoptions. In

addition, actual EV hourly load profiles were used to forecast future impact of EVs on both customer and system peak demands." (page 15)

QUESTION(S):

a) With respect to the first reference in the Preamble, please confirm that the baseline forecasts that were scaled up were the 2026-2030 forecasts by customer class including the impact of customer classification and new eDSM but excluding the impacts of EV and large load electrification.

i. If not confirmed, please explain the basis for the baseline forecasts that the load profiles were scaled to.

b) Exhibit 7-1-1(G) indicates that load profile used for LDEV load was based on daily load shapes provided by Black and Veatch in their 2023 Decarbonization Study. However, Exhibit 3-1-1 indicates that actual EV hourly load profiles were used to forecast future impact of EVs. Please reconcile.

c) Please provide the load profile(s) used for LDEV load (e.g. typical day by month).

d) Exhibit 7-1-1(G) indicates that the load profile used for large load electrification was based on daily load shapes provided by Black and Veatch in their 2023 Decarbonization Study which assume space heating is the primary use. However, in Exhibit 3-1-1 Hydro Ottawa indicates that the new large loads reflect the transition to electric heating and cooling systems, and electric industrial water heating. Given the end uses associated with the new Hydro Ottawa large load why is it appropriate to use a load profile that primarily reflects electric heating load?

e) Please provide the load profile(s) used for Large Commercial Incremental Load (e.g. typical day by month).

f) The addition of the Large Commercial Incremental Load resulted in some customers being reclassified as Large Use customer and their entire load (including the initial baseline load) being reclassified to the Large Use class. Please explain how their initial baseline forecast load was treated for purposes of determining the load profile (and resulting demand allocators) for the Large Use (e.g., was it included and treated the same as the new Large Commercial Incremental Load?).

RESPONSE(S):

a) Confirmed.

b) Hydro Ottawa clarifies that LDEV load shapes for electrification for both Demand Factor (Attachment 7-1-1(G) - 2026 Demand Allocators) and revenue load forecast (Schedule 3-1-1 - Revenue Load and Customer Forecast) were based on actual LDEV data. Load shapes for the commercial portion of the Demand Factor electrification load profile were based on daily load shapes provided by Black and Veatch.

c) Please refer to 3.0-VECC-34 response b).

d) The Black and Veatch study considered specific load profiles relevant to Hydro Ottawa's service area, which informed the development of electrification load profiles that demonstrate winter peaking. For that reason, heating has been identified as a major driver of large load electrification, although not the only one. The influences on electrification described in Schedule 3-1-1 - Revenue Load and Customer Forecast should also not be read as exhaustive. Hydro Ottawa considers the Black and Veatch profiles appropriate to use as a base for development of demand profiles because they reflect anticipated local electrification patterns.

e) Please see Figure A for 2026 Summer load profile and Figure B for 2026 Winter load profile by month for Large Commercial Incremental Load. Figure C and D display the hourly load for 2030 Summer and Winter load profile by month (5 to 10).

Figure A - 2026 Summer Large Commercial Incremental Load Profile

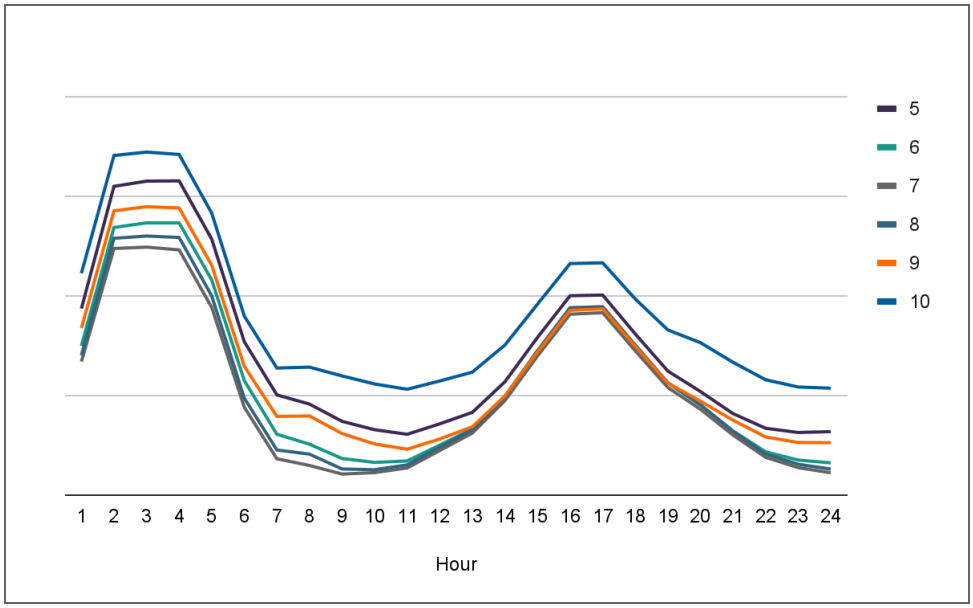


Figure B - 2026 Winter Large Commercial Incremental Load Profile

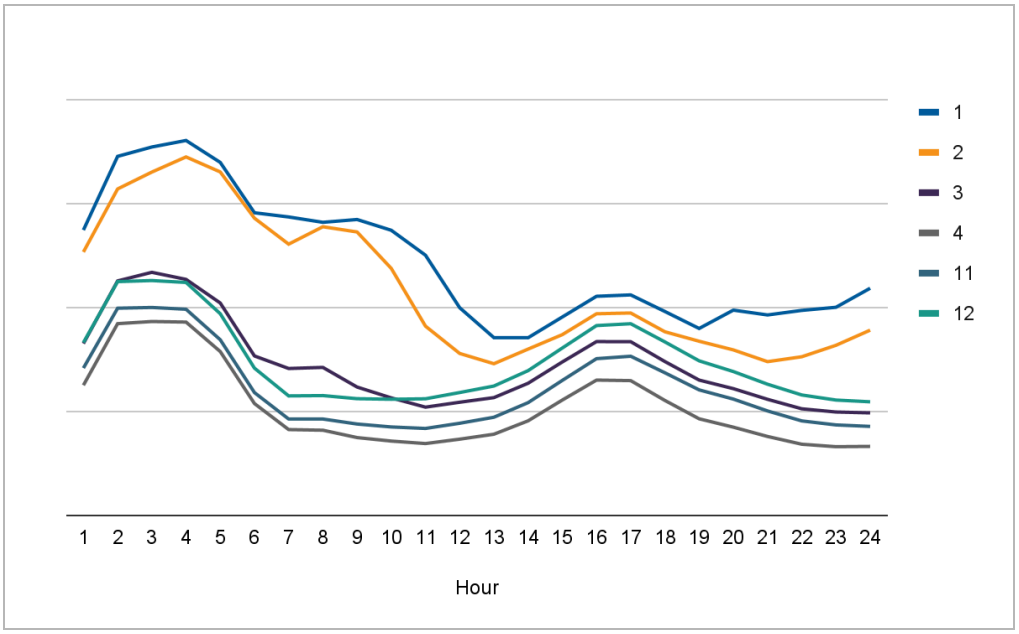


Figure C - 2030 Summer Large Commercial Incremental Load Profile

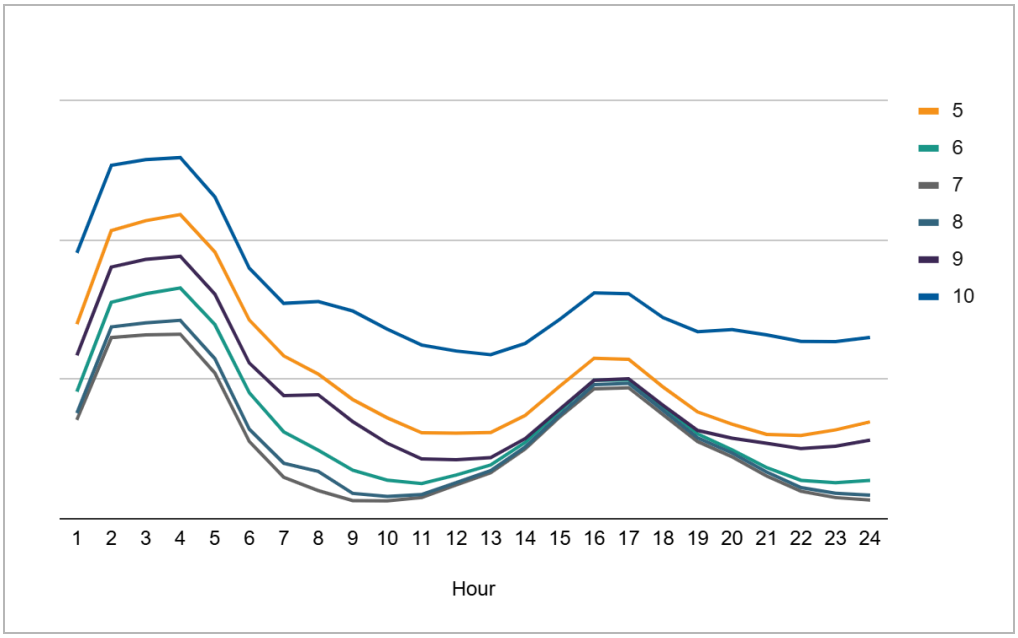
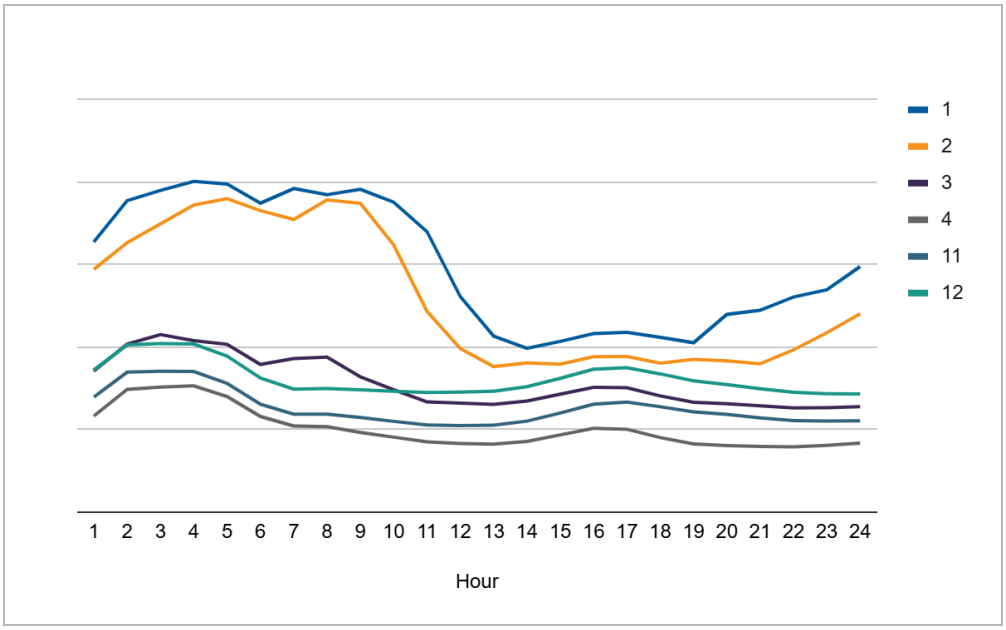


Figure D - 2030 Winter Large Commercial Incremental Load Profile



f) As detailed in Attachment 7-1-1(G) - 2026 Demand Allocators, historical load profiles by customer class are scaled up to test period (2026-2030) baseline revenue load forecast to create baseline demand profiles that inform the demand factors on Tab I8 of the cost allocation models. Historical load data for those customers to be reclassified as Large Use in the test period were left in their original customer class profiles for the purpose of this calculation.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-57

EVIDENCE REFERENCE:

Exhibit 7-1-1(G), pages 11-15

QUESTION(S):

a) The referenced pages describe how the CP and NCP values determined for 2018-2023 were trended to determine the 2026 CP and NCP values for each class. Please provide the tending equations used to determine the 12CP and 4NCP values for each class for 2026.

i. Please indicate for which of these trend equations the value for the trend coefficient is(statistically) significantly different from zero.

b) The referenced pages describe how the CP and NCP values determined for 2018-2023 were trended to determine the 2026 CP and NCP values for each class. Were the CP and NCP values used in the 2027-2030 Cost Allocations determined in a similar manner by i) scaling the results for 2018-2023 based on the relevant year's load forecast and ii) trending the results up to the relevant forecast year?

I. If not, how were they determined?

c) Please provide the calculations setting out the derivation of the 2027-2030 12CP and 4NCP demand allocators for the Residential class.

RESPONSE(S):

Note that responses are based on the updated cost allocation models submitted as response to Attachments 1-Staff-1(H) to (L) 2026-2030 Cost Allocation Models. In response to interrogatory 7-Staff-195, the 4 NCP demand factors for Street Lights have been recalculated as an average of the 5 historical years. Please see interrogatory 7-Staff-195 for a discussion of this change.

a) The model uses the MS Excel forecasting formula to determine best fit CP and NCP values for each class for 2026. The formula is structured as:

=FORECAST(x, known y's, known x's)

Where: x = year to be forecasted (2026)

Known x's = years for which historical data is presented (2020-2024)

Known y's = calculated CP. NCP values for historical years (2020-2024).

i. Please see the P-values of Trend Coefficients for 2026 in the Table A below.

Table A - P-value of Trend Coefficients for 12CP and 4NCP Values - 2026

Customer Class	P-value of Trend Coefficients 2026	
	12 CP	4 NCP
Residential	0.1450	0.9677
GS <50kW	0.8727	0.4897
GS 50-1499kW	0.9855	0.4984
GS 1500-4999kW	0.3578	0.0330
Large Use	0.4641	0.1892
Street Lights	0.0991	-
USL	0.1780	-

A p-value for USL - 4 NCP could not be computed in Table 1, as the value is consistent throughout 2020-2024. Per the discussion above, the 4 NCP values for Street Lights have been recalculated as an average of the historical years, so no p-value is assigned.

b) Yes, the values for the years 2027 - 2030 were determined in the same manner as the values for 2026.

c) Please see the response to part a). The calculations were done in the same manner for each year.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-58

EVIDENCE REFERENCE:

Exhibit 7-1-1(A) – 2026 Cost Allocation Model

QUESTION(S):

a) In the 2026 Cost Allocation Model, the GS 50-1,499 class has: i) in Tab I6.2 - 70 customers with 2 having Standby; ii) in Tab I7.1 – 70 meter units and iii) in Tab I7.2 – 70 meter reading units. Please confirm that each of the customers in the GS 50-1,499 class only has one meter that is owned/read by Hydro Ottawa, including those two customers also on the Standby Power rate.

b) In the 2026 Cost Allocation Model, the GS 1,500-4,999 class is shown as having 126 meters (Tab I7.1) but only 70 meter reading units (Tab I7.2). Please reconcile.

c) In the 2026 Cost Allocation Model, the Large Use class is shown as having 35 meters (Tab I7.1) but only 11 meter reading units (Tab I7.2). Please reconcile.

d) In the 2026 Cost Allocation Model (Tab I7.1 and Tab I7.2) why are there no meters associated with any of the three Standby classes but each class has 2 meter reading units?

e) Please confirm that all of the six Standby customers are served at primary voltage (per Tabs I6.2 and I8).

RESPONSE(S):

Hydro Ottawa has noted an error in the question of part a) and has responded to the question based on the number of customers (Tab I6.1), meters (Tab I7.1), and meter reading units (Tab I7.2) for the 50-1,499 kW class in Attachment 7-1-1 (A) - 2026 Cost Allocation Model which is 3,137.

a) As noted in tab I7.1 Meter capital, Hydro Ottawa has 3,137 meters for the GS 50 - 1,499 customer class.

b) The instructions for tab I7.1 of the cost allocation model state that, in general, the cost of one meter per customer should be included in the worksheet; in other words meter count and customer count should be equal for most customers. Following this instruction, the weighted meter installation cost for most customers would be calculated as:

*average meter installation cost * number of customers*
= total average weighted meter installation cost.

This method does not account for the fact that Hydro Ottawa's larger customers, in the GS 1,500-4,999 kW and Large Use classes, typically have more than one meter. Based on a weighting of one meter per customer, costs related to Meter Expense and Maintenance would be under allocated to those classes and consequently over allocated to Residential and GS < 50kW. For this reason, Hydro Ottawa has inputs the number of meters to weight meter capital costs on input Tab I7.1 Meter Capital by number of meters rather than number of customers.

Number of customers is an appropriate allocation base for meter reading (Tab I7.2) as billing determinants are typically accumulated once per billing period for all customer classes.

c) Please see the response to part b).

d) Generation meters are owned by the customer and are therefore not included in the calculation of weighted costs on Tab I7.1. Hydro Ottawa does, however, read the meters for standby billing purposes and they are therefore included in the calculation of weighted values for meter reading on Tab I7.2.

e) Confirmed.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-59

EVIDENCE REFERENCE:

Exhibit 7-1-1(A) to Exhibit 7-1-1(E) – 2026 to 2030 Cost Allocation Models
Exhibit 6-1-1(A) to Exhibit 6-1-1€ - 2026 to 2030 RRWFs
Exhibit 1-3-1, pages 15 and 19

Preamble:
Exhibit 1-3-1 describes how Hydro Ottawa proposes to update the annual inflation factors used to determine working capital and OM&A for the OEB's approved parameters.

QUESTION(S):

a) Please confirm that the 2027-2030 Service Revenue Requirements (SRRs) and Base Revenue Requirements (BRRs) used in the Cost Allocation Models and RRWFs for those years are "placeholders" and that the values used to set the approved rates for each of these years are likely to actually differ.

b) Assuming the Service Revenue Requirements (SRRs) and Base Revenue Requirements (BRRs) used to determine the rates to be approved for 2027-2030 differ from those used in the Cost Allocation Models and RRWFs available at the time 2026 rates are approved, please explain how the SSRs and BRRs (as determined when the rates are being set for 2027-2030) will be allocated to customer classes.

i. To illustrate this calculation, please provide the calculations demonstrating how the

revenue requirement associated with each customer class would be determined for purposes of setting 2027 (i.e., in 2026) assuming the 2027 SSR is then calculated to be $370,000 k as opposed to the current forecast of $335,440 k. Included in these calculations should be the Revenue to Cost Ratio adjustments Hydro Ottawa is proposing for 2027.

RESPONSE(S):

a) Confirmed, the Service Revenue Requirements (SRR) and Base Revenue Requirements (BRR) for the years 2027-2030 are forecasted values at time of submission of the 2026-2030 Rate Application. These values are subject to change based on the annual rate applications for those years are submitted.

b) For its 2021-2025 rate application, Hydro Ottawa submitted a single cost allocation model for 2021 which served as a cost allocation template for the four years following.

For the upcoming 2026-2030 rate application, Hydro Ottawa has submitted a separate cost allocation model for each of the five years. Each model, as approved as part of the CIR application, will then become the allocation template for the year represented.

i) Please refer to Attachment 7-VECC-59(A) - 2027 Revenue Allocation Example. To illustrate the example calculation the 2027 “Approved as part of 2026 Application” align with the values calculated in the original Cost Allocation Model submitted as Attachment 7-1-1(B) - OEB Workform - 2027 Cost Allocation Model, the prior year approved rates align with the rate design calculated in Attachment 6-1-1(A) - OEB Workform - 2026 Revenue Requirement Workform, and the 2027 Revenue Load forecast is the original forecast detailed in Schedule 3-1-1 - Revenue Load and Customer Forecast.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-60

EVIDENCE REFERENCE:

Exhibit 7-1-3, page 2-4
Exhibit 8, Attachment 8-5-1(A) – Current Tariff Schedule Tab

Preamble:
Exhibit 7-1-3 describes Hydro Ottawa's current Standby Rates and how they are applied.

QUESTION(S):

a) Attachment 8-5-1(A) sets out the 2025 values for the Standby Service Charge and Volumetric Rate for each of the three Standby Classes. However, it does not indicate what the 2025 rates are for the Backup Overrun Adjustment. Please provide.

b) Please outline how the current Standby Rates are determined and indicate what the proposed 2026 Standby Rates (i.e., service charge, volumetric rate and backup adjustment rate) for each of the three Standby Rate classes would be if there were no changes to the rate design.

c) With respect to the three examples set out on page 3, please confirm (or otherwise explain why not) that under the current rate design:

I. Under example 1, the Standby customer would pay more than if it had no Contract Demand and this additional amount would be equal to: i) the Standby Service Charge plus ii) the Contract Backup Demand of 800 kW times the applicable Standby Volumetric Rate.

ii. Under example 2, the Standby customer would pay more than if it had no Contract Demand and this additional amount would be equal to the Standby Service Charge.

iii. Under example 3, the Standby customer would pay more than if it had no Contract Demand and this additional amount would be equal to: i) the Standby Service Charge plus ii) 550 kW times the applicable Standby Volumetric Rate.

d) Under the circumstances where the nameplate rating was 1,000 kW, the Contract Demand was 800 kW, the Generator OFF Peak was 1,200 kW and the Generator ON Peak was 200 kW, would the current total Standby charge be determined as: i) the Standby Service Charge plus ii) 200 kW (1,200-200-800) times the Backup Adjustment rate/charge?

i. If not, please explain how the total charge would be calculated.

RESPONSE(S):

a) The same 2025 approved volumetric Standby rates are applied for the Backup Overrun Adjustment charge.

b) The current Standby rates are determined based on the total revenue at status quo rates, applying the existing fixed revenue percentage to determine the split of fixed/variable revenue and then dividing by the applicable billing determinants. The proposed 2026 Standby rates calculated using the current rate design are provided in Table A. These rates have been calculated based on the updated Revenue Requirement and Cost Allocation in 1-Staff-1.

Table A - Proposed 2026 Standby Rates with Status Quo Rate Design

	2026
Monthly Service Charge	$223.00
General Service 50-1,499 kW	$2.9759
General Service 1,500-4,999 kW	$2.7297
Large User	$3.0293

c)

i) Confirmed. Hydro Ottawa reserves the right to apply a contract for Backup Demand if a customer fails to meet its obligations and uses Hydro Ottawa for back-up service.

ii) The standby service charge applied to all customers who request standby service from Hydro Ottawa. The monthly service charge is the same amount for all customers, no matter the amount of contracted demand (kW) they request.

iii) Confirmed.

d) Confirmed.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-61

EVIDENCE REFERENCE:

Exhibit 7-1-3, pages 2 and 4-6
Attachment 8-5-1(A) – Final Tariff Schedule Tab

Preamble:
At page 2 Exhibit 7-1-3 states the following regarding the design of Ottawa Hydro's current Standby Rates:
"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."
Exhibit 7-1-3 describes Hydro Ottawa's proposed changes to its Standby rate design.

QUESTION(S):

a) Do the rate design principles set out on page 2 also apply to Hydro Ottawa's proposed Standby rates?

b) Please describe the how the distribution infrastructure required to supply a customer with embedded generation differs from that required to supply a customer without embedded generation where both have the same gross load requirements.

c) Please explain the rationale for each of the following proposed changes to the design of Standby rates and how it aligns with the principles set out on page 2:

I. Setting the standby volumetric charge as 50% of the distribution volumetric charge for the applicable rate class.

Ii. Setting the backup adjustment charge at the distribution volumetric charge for the applicable rate class.

d) The Exhibit states: "The fixed standby charge is applied to all Customers with load displacement generator(s) that exceed 499 kW." Under Hydro Ottawa's proposal are customers with embedded generation of 500 kW (or more) required to contract for Standby Power?

e) With respect to example 3 (page 5), please explain how the Billed Backup Demand value of 250 kW was calculated. Based on the formula provided it appears the value should be 350 kW (i.e., Contract Demand (800 kW) minus ((Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW)=250 kW) minus ((the lower of Metered Peak generator ON or 500 kW)=200 kW).

f) Please provide a revised example of the Backup Overrun Adjustment calculation where the Contract Demand is 100 kW (as opposed to zero kW).

g) Please provide the rationale behind the proposed calculation of the Backup Overrun Adjustment quantity (per page 5)

h) Please confirm that, if the customer's gross load peak demand occurs when the generation is OFF, it is possible for the difference between the "Metered Peak Generator OFF" and the "Metered Peak Generator ON" to exceed the Contract Demand even when the Contract Demand equals the nameplate rating of the generator.

I. If not confirmed, please explain why.

ii.If confirmed, can the proposed Backup Overrun Adjustment calculation produce a kW result that exceed the nameplate rating of the embedded generation and, if so, why is such a result appropriate?

i) Based on the proposed 2026 GS 50-1,499 Rates and the proposed 2026 GS 50-1,499 Standby Rates, please provide a schedules that, for each of the three examples plus example 3 with a 100 kW Contract Demand, set out the calculation of the total monthly bill (i.e., inclusive of billing for the standard distribution rates and the standby rates) would be assuming: i) the customer had embedded generation and a Contract Demand of 800 kW, ii) the customer had embedded generation of 800 kW and no Contract Demand, and iii) the customer had the same gross load requirements and no embedded generation. Please provide the schedules for two different scenarios regarding the customer's gross load:

I. First, where the customer's gross load requirement peak occurs when the generation is ON, and

Ii. Second, where the customer's gross load requirements peak occurs when the generation is OFF.

j) Based on the proposed 2026 GS 50-1,499 Rates and the proposed 2026 GS 50-1,499 Standby Rates, please also provide a schedules that for example 3 set out the calculation of the total monthly bill (i.e., inclusive of billing for the standard distribution rates and the standby rates) would be assuming: i) the customer had embedded generation with a nameplate of 800 kW and a Contract Demand of 100 kW, ii) the customer has embedded generation with a nameplate of 800 kW and no Contract Demand, and iii) the customer has the same gross load requirements and no embedded generation. Please provide the schedules for two different scenarios regarding the customer's gross load:

I. First, where the customer's gross load requirement peak occurs when the generation is ON, and

Ii. Second, where the customer's gross load requirements peak occurs when the generation is OFF.

RESPONSE(S):

a) The proposed Standby rate structure is designed to recover incremental costs while supporting Customers to use their standby generators more strategically.

b) For a customer with embedded generation, the distribution infrastructure must be capable of handling bi-directional power flow. This is a fundamental difference from the infrastructure needed for a conventional customer without embedded generation, which is only designed for uni-directional power flow from the grid to the customer. Even if both customers have the same gross load, the customer's system with embedded generation has to accommodate both the consumption of electricity and the potential export of excess electricity back to the grid. The Customer pays the required bi-directional meter, monitoring and control box. Key differences in infrastructure are listed below-

Power Flow and Protection:

- Uni-directional (No embedded generation): The grid's protection systems are designed to detect faults and isolate them based on the assumption that power flows in one direction. The infrastructure is simpler and built to deliver electricity.
- Bi-directional (with embedded generation): The introduction of embedded generation can cause power to flow in the reverse direction. The distribution infrastructure must be upgraded with bi-directional meters and more sophisticated protective relays that can handle two-way power flow. This is critical for safety and grid stability, as reverse power flow can create safety hazards for crews and interfere with existing protection schemes.

Voltage and Stability Management:

- Uni-directional: The grid is designed with specific voltage and stability parameters that assume a predictable load. The distribution network is a passive system that simply delivers power from a centralized source.

- Bi-directional: Embedded generation can cause voltage fluctuations on the distribution network. When a generator exports power, it can raise the voltage at that point in the grid, which can affect power quality for other customers. The infrastructure for an embedded generation customer must include technologies like smart inverters and other grid-edge controls that can regulate voltage and maintain system stability

Monitoring and Control

- Uni-directional: Monitoring is primarily focused on measuring the amount of electricity consumed by the customer.
- Bi-directional: To manage two-way power flow and ensure the safety and reliability of the grid, real-time visibility and control over the embedded generation source is required. This means advanced supervisory control and data acquisition (SCADA) systems and communication technologies to monitor and control the generation output, especially for larger systems.

c)

i. Hydro Ottawa has proposed to set the volumetric standby rates at 50% of the distribution service charge to balance between costs and benefits of customers that have behind-the-meter generators. In addition, please refer to interrogatory responses 2-Staff-55, 2-Staff-109, 2-CO-22 and 1-PP-7.

ii. Setting the backup adjustment charge at the distribution volumetric charge (i.e. double the standby volumetric rate) is proposed to encourage the customer to contract the appropriate amount of Backup Demand (kW) to support planning needs.

d) No, customers with generation over 499 kW are not required to sign for contracted Standby Service. However, Hydro Ottawa reserves the right to impose a contracted amount should the customer be using Hydro Ottawa in a Standby service capacity.

e) A typo exists, and the value in the example should be 350kW. Please also see interrogatory response 1-Staff-1, Section 7.1 and 1-Staff-196 question (b).

f) In the Backup Overrun Adjustment example provided in Section 4.2 of Schedule 7-1-3 - Standby Service Charge, if the Contract Demand is 100 kW and the Metered Peak Generator OFF was 550 kW then the Backup Overrun Demand would be 50 kW. The calculation would be as follows; Contract Demand of 100 kW - (Metered Peak generator OFF of 550 kW – Metered Peak generator ON of 200 kW) minus the lower of Metered Peak generator ON or 500 kW.

g) Hydro Ottawa has proposed to keep the Backup Overrun Adjustment as it is a mechanism to encourage customers to contract the appropriate amount of Contract Demand kW or load displace should they not want to use standby services. It has been Hydro Ottawa's experience that when the back-up over run rate is set to the same value as the standby variable rate some customers choose to not set a contracted rate however use the system for back-up capacity. This situation is not ideal for system planning.

h)

i) Please note Hydro Ottawa is not proposing to charge standby on a gross load peak basis. Gross load peak in this context is the sum of the hourly peak when the generator is ON and OFF. It is possible for the difference between the Metered Peak Generator OFF (the highest hourly demand when the generator is not running) and the Metered Peak Generator ON (the highest sum of demand measured in five minute intervals when the generator is running) to exceed the Contract Demand. This can happen even if the contract demand is equal to the generator's nameplate rating. The reason for this is it depends on how the generator(s) are deployed. The generator(s) could be off for five minutes while the premise is drawing load greater than the nameplate capacity of the generator(s).

Where the difference of Metered Peak Generation OFF - Metered Peak Generation ON exceeds the Contracted Demand (kW) amount, the Backup Overrun charge applies. As described in Schedule 7-1-3 - Standby Service Charge, section 3.2 the Backup Overrun adjustments charged to the customer never exceed the total nameplate rating of the load displacement generator.

ii) N/A

i) Hydro Ottawa has provided the requested distribution bill impact calculations in Table A, based on the examples provided in Schedule 7-1-3 - Standby Service Charges. The gross load requirement peak of the customer with and without generation has been assumed to be 1,000 kW, and the 800 kW generator is offsetting the full nameplate capacity when it is in use (i.e. Peak Generation ON is always 200kW).

The below examples provided are for illustrative purposes only, showing the standby charge for a single month and calculations have been simplified. One month's comparison does not accurately represent a customer's total annual reserve capacity needs. In addition this comparison should not be considered guidance for making decisions about whether or not to contract for reserve capacity.

Example 3 is a theoretical outcome and Hydro Ottawa has not seen this outcome in historical standby charges. Customers in this situation have likely opted out of a standby contract; standby charges are not applied (see result in the far right column below). Instead, monthly load peaks have been captured and billed through their primary load account. Hydro Ottawa monitors these Customers' peak usage to ensure appropriate standby charges are applied where applicable.

Table A - General Service 50-1,499 kW Proposed Distribution and Standby Charge

	Example 1 - GEN ON ENTIRE PERIOD	Example 2 - GEN OFF ENTIRE PERIOD	Example 3 - 800 kW Contract	Example 3 - 0kW Contract Demand	Example 3 - 100 kW Contract	Example 3 - 800 kW Contract	Example 3 - 0kW Contract Demand	Example 3 - 100 kW Contract	Customer No embedded Generation	Example 3 - No Contract Demand
			Gross load Peak GEN ON	Gross load Peak GEN ON	Gross load Peak GEN ON	Gross load Peak GEN OFF	Gross load Peak GEN OFF	Gross load Peak GEN OFF		Gross load Peak GEN OFF
Monthly Distribution Service & Volumetric Charge	$ 1,806.02	$ 8,230.10	$ 3,813.55	$ 3,813.55	$ 3,813.55	$ 8,230.10	$ 8,230.10	$ 8,230.10	$ 8,230.10	$ 8,230.10
Standby Charge	$1,391.21	$186.89	$1,591.93	$2,194.42	$1,391.41	$588.33	$1,792.91	$989.90	$0.00	$0.00
TOTAL PRE-TAX	**$ 3,197.23**	**$ 8,416.99**	**$ 5,405.48**	**$ 6,007.97**	**$ 5,204.96**	**$ 8,818.43**	**$ 10,023.01**	**$ 9,220.00**	**$ 8,230.10**	**$ 8,230.10**

j) See Table A in response (i).

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

7.0-VECC-62

EVIDENCE REFERENCE:

Exhibit 7-1-1, pages 14-18

QUESTION(S):

a) Please explain why the section dealing with the proposed revenue to cost ratio adjustments does not address (or even discuss) the fact that the revenue to cost ratios for the Standby classes are all significantly than 80% and does not propose any adjustments to the revenue to cost ratios for these classes.

RESPONSE(S):

a) As detailed in Table 7 of Schedule 7-1-1 - Cost Allocation, the OEB does not have defined revenue-to-cost ratio ranges for the standby service classification[1]. As such, Hydro Ottawa has not proposed any adjustments to the revenue-to-cost ratios. This approach aligns with the revenue-to-cost ratios for the Standby Service class approved throughout the 2021-2025 Custom IR term, which remained at 33.23%.

[1] Ontario Energy Board, *Report of the Board Review of Electricity Distribution Cost Allocation Policy,* EB-2010-0219 (March 31,2011), Page 36

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

8.0-VECC-63

EVIDENCE REFERENCE:

Exhibit 8-1-2, pages 6-7

Preamble:
The Application states:
"Hydro Ottawa proposed keeping the current fixed/variable split in determining the fixed charge to ensure the majority of General Service <50 kW rate class customers are not paying less than a Residential customer."

QUESTION(S):

a) Based on Hydro Ottawa's proposed 2026 rates for the Residential and GS<50 classes, what proportion (%) of GS<50 customers will be paying more than a Residential customer? As part of the response please indicate how the comparison is made (i.e., is it based on total bill, the portion of the bill based the fixed and variable distribution charges, or some other basis?).

b) Assuming the GS<50 fixed charge was set at the "ceiling" of $27.02 (per Table 6), what proportion (%) of GS<50 customers would be paying more than a Residential customer?

RESPONSE(S):

Note that responses are based on updated cost allocation and rate data submitted in response to interrogatory 1-Staff-1.

a) The proposed rates for GS < 50 kW customer class create a crossover situation where some GS < 50 kW customers will receive a lower monthly bill than Residential customers, based on distribution monthly service charge and volumetric rate. Table A below depicts that crossover point at 357 kWh billed consumption.

GS < 50 kW customers consuming less than that amount of kWh monthly will be charged less for distribution services than a Residential customer with a proposed fixed monthly service charge of $40.88. In 2024, 22% of GS < 50 kW customers fell below this break even point in 6 or more months. Eight percent fell below in all 12 months and 35% of customers fell below the threshold at least once during the year. Overall, 65% of GS < 50 kWh customers would be expected to pay more for monthly distribution services at least once during a twelve month period.

b) Using the updated proposed rates in interrogatory response 1-Staff-1. Holding the GS < 50 kW fixed rate at the calculated ceiling of $26.89 increases the variable rate for the class from $0.0362 to $0.0367. Compared to the proposed Residential fixed rate of $40.88, GS < 50kW customers consuming less than 381 kWh in a billing period in this scenario would receive a bill for distribution services that is less than the Residential fixed rate. In 2024, 36% of GS < 50 kW customers fell below this threshold in at least one billing period, 23% fell below it in at least 6 billing periods and nine percent fell below in all 12 billing periods.

Table A - Comparison of Ceiling and Proposed Fixed Rates GS < 50 kWh - 2026

Customer Class		Fixed Rate	Variable Rate
Residential Proposed		$40.88	
GS < 50 kWh			
	Ceiling Fixed	$26.89	$0.0367
	Proposed Fixed	$27.94	$0.0362
Break Even GS < 50 kWh			
	Ceiling Fixed kWh	381.20	
	Proposed Fixed kWh	357.46	

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

8.0-VECC-64

EVIDENCE REFERENCE:

Exhibit 8-2-1, pages 2-3
Exhibit 8-1-2(A) - RTSR Workform

QUESTION(S):

a) Please confirm that the RRR data used in Tab 3 and the billing data used in Tab 5 are both based on 2023 actuals.

RESPONSE(S):

a) Confirmed. Hydro Ottawa has provided an updated 2026 RTSR model which includes 2024 RRR and billing data as Attachment 1-Staff-1(D) - 2026_RTSR_Workform_EV.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

8.0-VECC-65

EVIDENCE REFERENCE:

Exhibit 8-2-1, page 5
Exhibit 8-1-2(A) - RTSR Workform, LV Rate Tabs

Preamble:
The Application states:
"Hydro Ottawa proposes to utilize the 'Low Voltage' tab in the OEB RTSR model to allocate the forecasted LV expense to customer classes for 2026-2030."

QUESTION(S):

a) Please provide the detailed calculations supporting the values for 2026-2030 LV expense (per Exhibit 8-2-1, Table 3).

b) Please clarify how Hydro Ottawa proposes the LV Rates for 2027-2030 will be set (e.g., will they be based on proposed RTSRs for each year {using the most current UTRs and updates to Tabs 3 and 5 using the most recent actuals}?).

RESPONSE(S):

a) See Attachment 8.0-VECC-65(A) - 2026 LV Expense for detailed calculations requested. The forecast methodology has also been described in Schedule 2-3-1 - Working Capital Requirement, Section 4.4. Hydro Ottawa notes there are slight rounding differences due to

converting the original low voltage forecast expense methodology detailed in Attachment 8.0VECC-65(A) to a per kWh basis for Appendix 2-Z calculations. The values submitted as part of Attachment 8-2-1(A) - OEB Workform - 2026 RTSR align with the Test Year 2026-2030 values calculated in Attachment 2-3-1(A) - OEB Appendix 2-Z - 2026 Commodity Expense to Attachment 2-3-1(E) - OEB Appendix 2-Z - 2030 Commodity Expense.

b) Confirmed, Hydro Ottawa proposes the 2027-2030 LV rates will be set annually based on the proposed RTSRs and RTSR model inputs for the corresponding year.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

8.0-VECC-66

EVIDENCE REFERENCE:

Exhibit 8-3-2, pages 3-5

Preamble:
The Application states:
"The proposed SSS rate is designed to recover costs for labour, material, and the working capital required to provide SSS services. The rate calculation included only incremental costs, which are detailed below:

- Incremental labour costs associated with administering the Regulated Price Plan (RPP) and commodity charges (Hourly Ontario Energy Price and Global Adjustment), include processes related to updating seasonal Time-of-Use hours and Tiered thresholds, and processing the Ontario Electricity Rebate;
- Incremental internal labour for wholesale market settlement activities;
- Incremental internal labor for monthly market settlement with the Independent Electricity System Operator, Hydro One, and embedded generators as well as associated internal/external reporting requirements;
- Vendor costs associated with administering the RPP, HOEP and Global Adjustment billing;

And

- Working capital expenses including the total cost of power and the Operations, Maintenance and Administration (OM&A) expenses detailed above."

QUESTION(S):

a) Please provide a schedule that breaks down the total SSS Administration cost estimate of $6,764,099 (per page 5) so as to show the costs contributed by each of the five areas identified in the Preamble.

b) Please confirm that the OM&A costs included in the propose 2026 Service Revenue Requirement do not include any of the incremental costs cited in the first four areas identified in the Preamble.

c) Please provide the calculation of the working capital expense included per the fifth area noted in the Preamble.

d) With respect to the working capital expenses included, what “cost of power” expenses have been included and why?

e) Has the working capital allowance included in Rate Base (per Exhibit 5) been adjusted to avoid any double counting of the working capital expenses included in the determination of the SSS Administration charge?

RESPONSE(S):

a) Please refer to interrogatory response 8-CCC-66 a).

b) Please refer to interrogatory response 8-CCC-66 b).

c) Please refer to interrogatory response 8-CCC-66 a).

d) The cost of power expenses included in the working capital calculation included in the SSS expense are the total cost of power expense (commodity, global adjustment, transmission, low voltage, and regulatory charges) as forecast in Attachment 2-3-1(A) - OEB Appendix 2-Z - 2026

Commodity Expense based on unadjusted forecast kWh. Hydro Ottawa did not include the loss factor adjustment as it acknowledges this is a distribution specific calculation and not an incremental expense of providing SSS administration services.

The working capital related to the cost of power expense was added to the SSS expenses as Hydro Ottawa would not incur these working capital costs if it did not bill/administer these services on behalf of the IESO and Transmittors.

e) Please see interrogatory response 8-CCC-66 b). Both OM&A and Working Capital Allowance included in the total revenue requirement are offset by Other Revenue amounts to determine the total base revenue requirement collected through distribution rates. As such, no double counting occurs.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

8.0-VECC-67

EVIDENCE REFERENCE:

Exhibit 8-4-1, pages 8-9
Attachment 6-3-1(A) – Appendix 2-H

Preamble:
Exhibit 8-4-1 discusses Hydro Ottawa's proposed rates for: i) Specific Access to Power Poles – Wireline Attachments and ii) Specific Access to Power Poles – Wireless Attachments.
Appendix 2-H breaks down Rent from Electric Property to show: i) Pole Attachment Revenue and ii) Duct Rental Revenue.

QUESTION(S):

a) Where is the revenue from Wireless Attachments included in Appendix 2-H?

b) What rates are charged for Duct Rental, how are they set and where are they discussed in the current Application?

c) Please provide evidence to support the statement that there is an "increased desire for third parties to move (wireline) assets underground" (per page 8)

RESPONSE(S):

a) Wireless Pole Attachment revenue is grouped under USofA account 4210, please refer to row 20 of Attachment 6-3-1(A) – Appendix 2-H - Other Revenue.

b) Duct rental agreements and rates are negotiated with the customer. Please refer to interrogatory response 6.0-VECC-45 question d) for details on Historical, Bridge and Test Year revenue breakdown (units and weighted average rate). Duct Rental Agreements are discussed in Schedule 6-3-4 - Other Operating Revenue.

c) During the Accelerated High Speed Internet Program run by the Government of Ontario beginning in 2022 until the end of 2025, Hydro Ottawa was prepared to receive an increased number of overhead wireline permit requests to accommodate Internet Service Providers (ISP) with the quick turnaround mandated through the program. However, Hydro Ottawa saw no overhead wireline permits through this program due to ISPs choosing to bury their services underground instead of attaching to poles, proving that third parties are looking to bury their new assets where possible.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

8.0-VECC-68

EVIDENCE REFERENCE:

Exhibit 8-4-1, pages 4-10

QUESTION(S):

a) Please provide a schedule that identifies: i) those specific charges that Hydro Ottawa proposed to hold constant at the 2026 approved charge for the years 2027-2030, ii) those specific service charges that Hydro Ottawa is proposing to set for the period 2027-2030 based on an annual escalation rate of 2.1%, and iii) those specific service charges that Hydro Ottawa is proposing will be updated annually for 2027-2030 based on new information (e.g. inflation factors) available at the time of approval.

RESPONSE(S):

a)

i) Please find Table A below for those specific charges that Hydro Ottawa proposed to hold constant at the 2026 approved charge for the years 2027-2030.

Table A - Rates Held Constant for 2026-2030

	2026	2027	2028	2029	2030
Arrears Certificate	$ -	$ -	$ -	$ -	$ -
Easement Certificate for Unregistered Easements	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Duplicate Invoices for Previous Billing	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00
Credit Reference/Credit Check (+ credit agency costs)	$ 20.00	$ 20.00	$ 20.00	$ 20.00	$ 20.00
Unprocessed Payment Charge (+ bank charges)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Account Set Up/Change of Occupancy Charge	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00

ii) Please find Table B below for those specific service charges that Hydro Ottawa is proposing to set for the period 2027-2030 based on an annual escalation rate of 2.1%.

Table B - Rates for 2027-2030 Based on an Annual Escalation Rate of 2.1%

	2026	2027	2028	2029	2030
Special Billing Service, per hour	$ 141.00	$ 144.00	$ 147.00	$ 151.00	$ 154.00
Interval Meter - Field Reading	$ 366.00	$ 374.00	$ 382.00	$ 390.00	$ 398.00
High Bill Investigation - If Billing is Correct	$ 322.00	$ 328.00	$ 335.00	$ 342.00	$ 350.00
Reconnect at Meter - Regular Hours	$ 70.00	$ 71.00	$ 72.00	$ 74.00	$ 76.00
Reconnect at Meter - After Regular Hours	$ 94.00	$ 96.00	$ 98.00	$ 100.00	$ 102.00
Reconnect at Pole - Regular Hours	$ 318.00	$ 325.00	$ 331.00	$ 338.00	$ 345.00
Reconnect at Pole - After Regular Hours	$ 480.00	$ 490.00	$ 500.00	$ 510.00	$ 521.00
Temporary Service - Install and Remove ("TS-I&R") - Overhead - no transformer	$ 1,079.00	$ 1,102.00	$ 1,125.00	$ 1,148.00	$ 1,172.00
TS-I&R - Underground - no transformer	$ 1,422.00	$ 1,452.00	$ 1,483.00	$ 1,514.00	$ 1,546.00
TS-I&R - Overhead - with transformer	$ 5,010.00	$ 5,116.00	$ 5,223.00	$ 5,333.00	$ 5,445.00
Energy Resource Facility Administration Charge	$ 165.00	$ 168.00	$ 172.00	$ 176.00	$ 179.00

iii) Hydro Ottawa is proposing to update the Wireline Pole Attachment charge annually based on the OEB approved rate. Please see interrogatory response 8-Staff-200 a) and Schedule 6-3-4 - Other Operating Revenues, Section 5.1 for further details.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

8.0-VECC-69

EVIDENCE REFERENCE:

Exhibit 8-4-2, page 3

QUESTION(S):

a) How many Net Metering customers does Hydro Ottawa currently have?

b) Are there any incremental costs associated with providing Net Metering Service that are not incurred to provide service to non-Net Metering customers in the same rate class?

I. If not, why not?

Ii If yes, please estimate what the total incremental costs are based on either: i) 2024 actual costs or ii) 2026 forecast costs.

RESPONSE(S):

a) Hydro Ottawa currently has 601 net metering customers as of June 30, 2025.

b) Any incremental costs associated with providing Net Metering Service that are not incurred to provide service to non-Net Metering customers in the same rate class are minimal.

i) The historical Net Metering charge was set based on recovering the costs incurred to bill the net metering customers manually. Hydro Ottawa has since automated this process resulting in large productivity benefits. Please refer to Schedule 1-3-4 - Facilitating

Innovation and Continuous Improvement Table 4 for quantifiable benefits and Section 3.2.1 for further details.

ii) See response to i).

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

9.0-VECC-70

EVIDENCE REFERENCE:

Attachment 9-1-5(A), 2015-2027 LRAM Tab

QUESTION(S):

a) With respect to the savings from 2020 Programs (Rows 991-1167) please identify those programs and program adjustments where Hydro Ottawa was responsible for or assisted with the management/delivery of the program.

b) With respect to savings from 2021 Programs (Rows 1199-1388) please identify those programs and program adjustments where Hydro Ottawa was responsible for or assisted with the management/delivery of the program.

c) With respect to savings from 2022 Programs (Rows 1419-1589) please identify those programs and program adjustments where Hydro Ottawa was responsible for or assisted with the management/delivery of the program.

d) With respect to savings from 2023 Programs (Rows 1620-1797) please identify those programs and program adjustments where Hydro Ottawa was responsible for or assisted with the management/delivery of the program.

RESPONSE(S):

a) With respect to savings from 2020 Programs (Rows 991-1167). Hydro Ottawa was responsible for the delivery of the Save on Energy Retrofit Program under the Conservation First Framework. The programs under the 2019-2020 (Interim) Framework were the responsibility of the IESO.

b) With respect to savings from 2021 Programs (Rows 1199-1388), Hydro Ottawa was responsible for the delivery of the Save on Energy Coupon Program and Save on Energy High Performance New Construction Program under the Conservation First Framework. The programs under the 2019-2020 (Interim) and 2021-2024 (New) Framework were the responsibility of the IESO.

c) With respect to savings from 2022 Programs (Rows 1419-1589), Hydro Ottawa was responsible for the delivery of the Save on Energy Retrofit Program under the Conservation First Framework. The programs under the 2021-2024 (New) Framework were the responsibility of the IESO.

d) With respect to savings from 2023 Programs (Rows 1620-1797), Hydro Ottawa was responsible for the delivery of the Save on Energy Process & Systems Upgrades Program under the Conservation First Framework. The programs under the Interim Framework were the responsibility of the IESO.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

9.0-VECC-71

EVIDENCE REFERENCE:

Exhibit 9-2-1, pages 1-3
Exhibit 7-1-1, page 3

Preamble:
The Application states:
“these programs prudently support the objectives outlined in the Ontario Energy Board's "Non-Wires Solutions Guidelines for Electricity Distributors" and aligns with the broader Framework for Energy Innovation, ultimately promoting the effective implementation of NWS for a more resilient and efficient electricity grid that benefits ratepayers.” (page 2)

QUESTION(S):

a) How does Hydro Ottawa plan on ensuring that actual expenditures recorded in the Non-Wires Solutions Variance Account are prudent expenditures that support a more resilient and efficient electricity grid?

b) When Hydro Ottawa seeks to refund/recover the balance in this account, what evidence does it plan on providing to demonstrate the prudence of the actual expenditures recorded?

c) With respect to Table 1 (page 2), how does Hydro Ottawa determine which NWS-related costs are to be included in OM&A versus Other Income and Deductions?

RESPONSE(S):

a) Hydro Ottawa will ensure that actual expenditures recorded in the Non-Wires Variance Account are prudent expenditures that support a more resilient and efficient electricity grid by ensuring NWS investments pass a NWS assessment in accordance with the OEB's Benefit Cost Analysis (BCA) Framework. For an explanation of how Hydro Ottawa's Non-Wires Customer Solutions Program portfolio and Battery Energy Storage System (BESS) projects align with the BCA Framework, please refer to the responses provided to interrogatories 2-Staff-67 and 2-Staff-111, respectively. These documents contain specific information and analysis on each topic. Please refer to response to interrogatory 2-ED-8 for how Hydro Ottawa will approach additional NWS opportunities not presently outlined within the application.

b) Please see response to part a) above. At the time of disposition Hydro Ottawa would provide comprehensive documentation supporting the costs incurred, any funding received from external parties, and the benefits realized. For additional information concerning the treatment of the NWS variance account, please refer to Hydro Ottawa's response to interrogatory 2-Staff-18.

c) Incentives to third parties as well as any margin on payments would be included in other revenue. Please also see Hydro Ottawa's response to interrogatory 2-SEC-53 for additional information.

INTERROGATORY RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

9.0-VECC-72

EVIDENCE REFERENCE:

Exhibit 9-2-1, pages 3-5
Exhibit 3-1-1, pages 9-10

Preamble:
The Application states:
"This account would be a mechanism to manage discrepancies between predicted large load requests as outlined in Table 8 of Schedule 3-1-1 - Revenue Load and Customer Forecast and actual billed demand for these large load requests. This would account for both volume and timing variations and would only be calculated for the period of time until the load substantially materializes, net of any adjustment in the customer contribution." (Exhibit 9-2-1, page 4)
And
"Hydro Ottawa's revenue load forecast includes electrification and large load requests based on future customer initiatives aimed at decarbonization and electrification, as well as anticipated commercial and residential transportation electrification. The growing popularity of EVs is expected to increase residential energy consumption, while municipal climate targets are driving the City's investment in electrified transportation. Tables 7 and 8 below provide the electrification and large load energy and demand requests respectively" (Exhibit 3-1-1, page 9)

QUESTION(S):

a) Is it Hydro Ottawa's proposal that the Large Load Variance Account include both: (i) the electrification of large loads and (ii) the electrification of residential and commercial transportation or just the former?

b) The reference from Exhibit 3-1-1 suggests that Table 8 includes the impact of both: i) large load electrification and ii) the electrification of residential and commercial transportation. Please clarify whether this is the case.

c) Based on the preceding responses, if necessary, please provide a revised schedule setting out the 2026-2030 “large loads” included in the load forecast.

d) How does Hydro Ottawa intend on distinguishing increases in load during the 2026-2030 period due to electrification as opposed to increases that may/will occur for other reasons?

RESPONSE(S):

a) Hydro Ottawa’s proposal is that the Large Load Variance Account includes only the electrification of large loads.

b) Table 8 from Schedule 3-1-1 - Revenue Load and Customer Forecast includes both the impact of large load electrification and the electrification of residential and commercial transportation (LDEVs).

c) Tables A and B have been provided which detail the kW for large load electrification and LDEV.

Table A - Large Load Electrification kW

	2024	2025	2026	2027	2028	2029	2030
GS 50-1000KW	0	0	0	0	0	0	0
GS 1000-1500KW	0	0	0	(16,261)	(30,407)	(30,408)	(30,408)
GS 1500-5000 KW	0	0	(25,026)	(25,025)	(25,025)	(25,025)	(25,025)
Large User	8	18,802	118,561	193,498	331,468	514,396	633,339
Street Light	0	0	0	0	0	0	0
Sentinel	0	0	0	0	0	0	0
Standby	0	0	0	0	0	0	0
TOTAL	**8**	**18,802**	**93,535**	**152,212**	**276,036**	**458,963**	**577,906**

Table B - LDEV kW

	2024	2025	2026	2027	2028	2029	2030
GS 50-1000KW	363	4,637	7,657	11,134	15,071	19,501	24,423
GS 1000-1500KW	48	612	1,001	1,453	1,967	2,545	3,185
GS 1500-5000 KW	36	457	754	1,096	1,483	1,919	2,404
Large User	8	108	177	257	348	450	564
Street Light	0	0	0	0	0	0	0
Sentinel	0	0	0	0	0	0	0
Standby	0	0	0	0	0	0	0
TOTAL	**455**	**5,814**	**9,589**	**13,940**	**18,869**	**24,415**	**30,576**

d) The large load electrification has been included in the revenue load forecast based on customer requests from signed Offer to Connects or submitted load summary forms. These are discrete projects, where the customer is requesting a large kW increase compared to their historical load requirements. Once the upgrade and/or expansion is energized, it will be assumed that any increase in billed kW demand (compared to the historical demand) is attributable to the “large load electrification”.