SETTLEMENT RESPONSES TO CONSUMERS COUNCIL OF CANADA

SC-CCC-1

EVIDENCE REFERENCE:

JT2.23

QUESTION(S):

Please confirm that Table B reflects the equipment and material costs included in the proposed capital plan.

RESPONSE(S):

Confirmed.

SETTLEMENT RESPONSES TO CONSUMERS COUNCIL OF CANADA

SC-CCC-2

EVIDENCE REFERENCE:

JT1.31

QUESTION(S):

The response to JT1.31 mentions a number of changes to the forecast timing and costs for the Cyrville MTS project and the Greenbank MTS project.

a) Please advise whether Hydro Ottawa is proposing to make updates to its capital plan related to these changes. Or is the information about timing and cost changes simply provided to support the economic evaluation?

RESPONSE(S):

Hydro Ottawa confirms it is proposing an update of its capital budget for both the Cyrville Municipal Transformer Station (MTS) and Greenbank MTS projects. The Cyrville MTS adjustments are driven by the acceleration of the Cyrville Municipal Transformation Station project timeline from 2032 to 2028 to serve a large customer. The Greenbank MTS adjustments are driven by changes to timelines and overall impacts to customer contributions. A capital expenditure variance analysis for each project is also included below.

Cyrville MTS:

The gross capital expenditure increase of [redacted] shown in Table A below under the Capacity Upgrade program is driven by the advancement of expenditures from 2031 and 2032 into this rate period as a result of the large load customer's energization timeline. Conversely, the [redacted] increase in capital expenditures in the System Expansion program is a net new capital requirement directly attributable to the large load customer. As shown in Table A below, the overall gross capital expenditures impact of the Cyrville MTS project related to System Service and System Access for 2026-2030 is therefore [redacted]. This gross capital expenditure increase is offset by an increase in forecasted customer contributions of [redacted], resulting in an overall net decrease in capital expenditures of [redacted].

In addition to the above, there is an incremental increase in gross capital expenditures of [redacted] in the Connection and Cost Recovery Agreement (CCRA) program under General Plant, as shown in Table B below. This increase in expenditures is offset by an increase in customer contributions of [redacted], leading to a net capital expenditure increase of [redacted]. The gross capital expenditures are increasing due to the advancement of the spend from 2031/2032 into the present rate period, as a result of the timelines of the large load customer.

The capital additions shown in Table C are likewise impacted for both of the programs and are aligned with the gross cost breakdown provided in updated JT1.31.

Greenbank MTS:

The gross capital expenditure decrease of [redacted] under the Capacity Upgrade program shown in Table A below is attributable to capital expenditures initially forecasted for 2026-2030 being advanced to 2024 and 2025 to account for longer lead times of major equipment purchases. This gross expenditure decrease is offset by an increase in gross capital expenditures of [redacted] in the System Expansion program. The need for System Expansion capital expenditures related to the customer connecting to the Greenbank MTS were missed during the budgeting process. Hydro Ottawa did however budget for two discrete placeholder projects in the System Expansion program within the 2026-2030, as per JT1.26. Hydro Ottawa is therefore proposing to offset the overall impact of gross capital expenditures by removing one of the discrete placeholders. Removal of the discrete placeholder of $10.5M leads to an overall net increase of [redacted] in gross capital expenditures within the System Expansion program (within System Access). The combined impact of the decreases/increases noted above is [redacted]. The gross capital expenditure increase is offset by an increase in forecasted customer contributions of [redacted], resulting in an overall net increase in capital expenditures of [redacted].

In addition to the above, a forecasted increase of [redacted] is also included in the CCRA program, as shown in Table B below. This increase is partially offset by an increase in forecasted customer contribution of [redacted], resulting in a net capital expenditure increase of [redacted]. This expenditure increase and associated increase in customer contributions are driven by updated budgets related to the transmission upgrades required for the station that were received from Hydro One.

The capital additions shown in Table C are likewise impacted for both of the programs and are aligned with the gross cost breakdown provided in updated JT1.31.

Table A System Access and System Service Capital Expenditures Updates for Cyrville & Greenbank MTS ($'000s)

Project	Program	Gross			Net		
		1-Staff-1	Revised	Variance	1-Staff-1	Revised	Variance
Cyrville MTS	System Access (System Expansion)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	System Service (Capacity Upgrade)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenbank MTS	System Access (System Expansion)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Greenbank MTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Discrete Placeholder	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	System Service (Capacity Upgrade)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL		**$ 113,220**	**$ 125,767**	**$ 12,547**	**$ 102,487**	**$ 98,875**	**$ (3,612)**

Table B General Plant (CCRA) Capital Expenditures Updates for Cyrville & Greenbank MTS ($'000s)

Project	Program	Gross			Net		
		1-Staff-1	Revised	Variance	1-Staff-1	Revised	Variance
Cyrville MTS	General Plant (CCRA)	[redacted]					
Greenbank MTS							
TOTAL				**$51,291**			**$39,091**

The overall impact on net capital additions and expenditures is presented in Table C and Table D.

Table C - Test Years Net Capital Additions by Investment Category as a result of Updated Cyrville & Greenbank MTS ($'000s)

Investment Category	2026-2030 Test Years		Var. ($)	Var (%)
	1-Staff-1	Revised		
System Access	$ 189,789	$ 196,147	$ 6,358	3%
System Renewal	$ 432,341	$ 432,341	$ -	0%
System Service	$ 452,066	$ 483,256	$ 31,190	7%
General Plant	$ 119,455	$ 158,546	$ 39,091	33%
NET CAPITAL ADDITIONS	**$ 1,193,651**	**$ 1,270,290**	**$ 76,639**	**6%**

Table D Test Years Net Capital Expenditures by Investment Category as a result of Updated Cyrville & Greenbank MTS ($'000s)

Investment Category	2026-2030 Test Years		Var. ($)	Var (%)
	1-Staff-1	Revised		
System Access	$ 173,228	$ 179,845	$ 6,617	4%
System Renewal	$ 431,704	$ 431,704	$ -	0%
System Service	$ 473,211	$ 462,981	$ (10,229)	(2)%
General Plant	$ 121,201	$ 160,292	$ 39,091	32%
NET CAPITAL EXPENDITURES	**$ 1,199,343**	**$ 1,234,821**	**$ 35,478**	**3%**

SETTLEMENT RESPONSES TO CONSUMERS COUNCIL OF CANADA

SC-CCC-3

EVIDENCE REFERENCE:
2-SEC-35

QUESTION(S): Update the conversion of capital expenditures to in-service additions provided in interrogatory response to 2-SEC-35 based on application updates.

RESPONSE(S):

Please refer to Excel Attachment SC-CCC-3(A) - Capital Expenditures - ISA Conversion. Note that this has been updated to reflect all application updates including SC-CCC-2, with the exception of the below note.

Please note that Attachment SC-CCC-3(A) - Capital Expenditures - ISA Conversion as well as the response to SC-CCC-2 does not include an update to the PILS Contribution included in capital expenditures or additions. The PILs contribution has been subsequently updated by and the total change in amount is $1.4M (Original amount $9.2M, Revised amount $10.6M for the years 2026 and 2027).

SETTLEMENT RESPONSES TO CONSUMERS COUNCIL OF CANADA

SC-CCC-4

EVIDENCE REFERENCE:

JT1.31

QUESTION(S):

Can you please advise whether Hydro Ottawa is planning to also update the load forecast for any changes associated with the information provided (i.e., change to station timing to serve a Large Load customer) in Undertaking JT1.31.

RESPONSE(S):

Hydro Ottawa confirms that the information provided in undertaking JT1.31 did not necessitate any updates to the load forecast or the revenue forecast.

The forecast for both planning and revenue load for the 2026-2030 Test Years already included the anticipated consumption and demand from the large load customers referenced JT1.31. The only changes required were the updates to the capital expenditure and related in-service timing, which were required for the purpose of accurately calculating the revenue requirement for the 2026-2030 Test Years.

SETTLEMENT RESPONSES TO CONSUMERS COUNCIL OF CANADA

SC-CCC-5

EVIDENCE REFERENCE:
SC-CCC-2

QUESTION(S): The response to SC-CCC-2 notes the following:

"The Cyrville MTS adjustments are driven by the acceleration of the Cyrville Municipal Transformation Station project timeline from 2032 to 2028 to serve a large customer… The gross capital expenditure increase of ___ shown in Table A below under the Capacity Upgrade program is driven by the advancement of expenditures from 2031 and 2032 into this rate period as a result of the large load customer's energization timeline."

In the context of the above noted statement that appears to say that service to the large load customer will now start earlier, can you please further explain the response to SC-CCC-4. As part of the response, can you please also provide a reference to the evidence where the load for this customer can be found as part of the revenue forecast.

RESPONSE(S):

Although revenue and planning forecasts were updated just before the original application submission to include last-minute adjustments—specifically the March 2025 large load customer request and the New Energy Efficiency Programs (announced January 7, 2025) — the financial reference base was finalized before these updates, so the associated costs for advancing this work into the current rate period were not incorporated.

As part of the revenue load forecast Hydro Ottawa does not make reference to specific customers names or what station they are being provided energy from. [redacted]

[redacted]

SETTLEMENT RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY & POLLUTION PROBE

SC-CO/PP-1

EVIDENCE REFERENCE:

QUESTION(S):

For each Grid Modernization Key Performance Indicator (KPI) and related metrics, please provide the baseline and proposed targets over the rate term.

RESPONSE(S):

Pursuant to Undertaking JT1.4, Hydro Ottawa is evaluating seven Grid Modernization Key Performance Indicators (KPIs). The specific outcomes measured and calculation methodologies for these KPIs are defined in Attachment JT1.4(A) - Hydro Ottawa Grid Modernization KPI Calculations.

The Grid Modernization KPIs are currently under development. Consequently, as confirmed during the Technical Conference (OEB_EB-2024-0115_20250922_DAY 1_87997, pages 28-30). As a result, no definitive baselines or proposed targets have been established for these specific KPIs. The following outlines the status of each KPI and references other relevant or related metrics within the application.

1. **System Observability**
    - Baseline: under development
    - Targets: under development
    - Related Metric: Controllability & Observability

- ■ As defined within Schedule 2-5-3 - Performance Measurement for Continuous Improvement, Table 27 on page 71 and defined on page 74.

2. System Controllability

- Baseline: under development
- Targets: under development
- Related Metric: Controllability & Observability
  - ■ As defined within Schedule 2-5-3 - Performance Measurement for Continuous Improvement, Table 27 on page 71 and defined on page 74.

3. Improved Grid Model Accuracy

- Baseline: under development
- Targets: under development
- Related Metric: N/A

4. Feeder Loading Index

- Baseline: Feeder Load Index (FLI) as defined within Section 8.4.2 of Schedule 2-5-4 - Asset Management Process
  - ■ Figure 70 on page 211 - count of feeder by FLI
  - ■ Table 32 on page 212 - listing of feeders with FLI 4 and 5
- Targets: under development
- Related Metric: N/A

5. Station Loading Index

- Baseline: Station Load Index (SLI) as defined within Section 8.4.1 of Schedule 2-5-4 - Asset Management Process
  - ■ Figure 69 on page 206 - count of stations by SLI
  - ■ Table 29 on page 207 - listing of stations with SLI 4 and 5
- Targets: As defined within Section 6.3 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement (page 73) and Section 2.1.10 of Schedule 1-3-2 - Customer Performance Scorecard (page 21)

    - Hydro Ottawa's target is zero stations with a Load Index of 4 or 5 by 2030. This is a five-year target based on the initiatives outlined in Schedule 2-5-8 - System Service Investments
- Related Metric:
    - Station Load Index - Section 6.3 of Schedule 2-5-3
    - Station Load Index - Section 2.1.10 of Schedule 1-3-2

6. DER Visibility & Management

- Baseline: under development
- Targets: under development
- Related Metric:
    - Customer Participation in Non-Wires Solutions - Section 2.1.3 of Schedule 1-3-2 (page 9)
    - Distributed Energy Resource Capacity - Section 2.1.12 of Schedule 1-3-2 (page 22)

7. DER Hosting Capacity

- Baseline: Restricted Feeders as defined with Table 37 in Section 9.3.3 of Schedule 2-5-4 - Asset Management Process (page 296) Short Circuit Capacity Constraints, Table 37
- Targets: under development
- Related Metric: N/A

SETTLEMENT RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY & POLLUTION PROBE

SC-CO/PP-2

EVIDENCE REFERENCE:

QUESTION(S):

Please provide a table of all third party non-wire alternatives directly supported by Hydro Ottawa (via contract of other support mechanism) by technology type (e.g. solar, battery, DR contract, etc.) and indicate what annual energy and peak demand reduction each provides.

RESPONSE(S):

Hydro Ottawa interprets “third party non-wire alternatives directly supported by Hydro Ottawa” as Non-Wires Solutions (NWS) that involve an active partnership with, or technical/financial support for, a third party, specifically to meet a distribution system need in place of traditional infrastructure. Currently, Hydro Ottawa is not directly supporting any third party NWS under this definition.

Hydro Ottawa has, however, proposed to deploy “third party non-wire alternatives directly supported by Hydro Ottawa” through its Non-Wires Customer Solutions Program (NWCSP) in targeted areas to address distribution system needs beginning in 2026, as described in section 9.2.2.1 of Schedule 2-5-4 - Asset Management Process, and also within the response to interrogatory 2-Staff-67. The NWCSP would allow Hydro Ottawa to incentivize customers to reduce facility demand, deploy behind-the-meter solar and battery energy storage as well as enroll in demand response programming. Within the initial targeted deployment area, Hydro Ottawa expects to acquire between 10MW and 15MW of capacity by deploying the NWCSP.

Furthermore, as mentioned in the responses to interrogatories 2-PP-12 part (a) and 8-ED-45 part (d), Hydro Ottawa has also executed the Electricity Demand-Side Management (eDSM) agreement with the Independent Electricity System Operator (IESO). Hydro Ottawa is committed to advancing the enduring provincial eDSM framework in a supporting role, beginning with the initial 2025-2027 eDSM plan,[1] leading to further opportunities for customers to participate in third party non-wires alternatives directly supported by Hydro Ottawa.

[1] Independent Electricity System Operator,"2025-2027 Electricity Demand Side Management Program Plan (with Beneficial Electrification)" https://ieso.ca/-/media/Files/IESO/Document-Library/eDSM/2025-2027-DSM-Plan-with-Beneficial-Electrification.pdf

SETTLEMENT RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY & POLLUTION PROBE

SC-CO/PP-3

EVIDENCE REFERENCE:

QUESTION(S):

JT1.28 notes that "The IRRP Forecast is the Reference Scenario forecast as represented in Table A of interrogatory response 3-CCC-34 combined with committed large load requests identified after the Decarbonization Study reference scenario was finalized". Can you confirm that the large load requests included are only those already attached or with signed contracts and do not include inquiries and submitted load summary form categories? Can you confirm the same for the revenue forecast Hydro Ottawa is using for rate term.

RESPONSE(S):

The large load requests considered within the IRRP Forecast are not only those already attached or with signed contracts, the large load requests with a submitted load summary as of April 2024 are also included.

The revenue load forecast includes the impact of certain large loads (MW), as detailed in Table A of JT4.14.

SETTLEMENT RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY & POLLUTION PROBE

SC-CO/PP-4

EVIDENCE REFERENCE:

QUESTION(S):

Hydro Ottawa indicated that they are taking a tempered approach for the reference scenario and would make changes later to meet the policy scenario. What actions would be required during the rate term to align with the policy scenario that are not already committed to in the reference scenario? Also, please provide any analysis or documentation on what would be needed following this term to catch up with the policy scenario. If no assessment has been done on this, please explain why not.

RESPONSE(S):

Hydro Ottawa has not undertaken any specific analysis to determine incremental investments or actions that would be required during the 2026-2030 rate term to fully align with the policy guided scenario.

Hydro Ottawa's 2026-2030 investment plan was not determined directly by the scenarios detailed in the Decarbonization Study. Forecasted system capacity and the resulting capital expenditures were based on immediate system needs and committed load requirements. Investment decisions were further augmented by the IRRP Forecast (Based on the Reference Scenario), as Hydro Ottawa believes this to be the most likely scenario for efficient capital deployment and optimized asset utilization. Since the policy scenario (which Hydro Ottawa states as the "Policy-Guided Scenario" in

Attachment 2-5-4(F) - Decarbonization Study) was not employed, its impact on capacity needs and associated capital expenditures therefore has not been assessed.

The decarbonization scenarios serve to augment mid-to-long-term investment planning. Consequently, a near-term convergence of load trends with the policy scenario is not anticipated to incrementally alter near-term investment decisions throughout the 2026–2030 period.

Hydro Ottawa continuously monitors system needs and adjusts plans accordingly, based on customer requirements to ensure adequacy of supply.

SETTLEMENT RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY & POLLUTION PROBE

SC-CO/PP-5

EVIDENCE REFERENCE:

QUESTION(S):

What investment in FLISR has Hydro Ottawa made and what is the proposed investment over the term. If FLISR has not been identified for implementation, please provide the assessment that resulted in that conclusion.

RESPONSE(S):

Hydro Ottawa's investment in Fault Location, Isolation, and Service Restoration (FLISR) is not a standalone investment, but is fully integrated as a core component of the broader Advanced Distribution Management System (ADMS) program. The proposed investments related to the ADMS program for 2026-2030 are provided in Section 3 of the ADMS Program Charter (Interrogatory Attachment 2-CCC-15(D) - ADMS Program Charter).

The 2025-2030 plans for the ADMS program, including its phased FLISR implementation, are detailed in Attachment 2-CCC-15(D) - ADMS Program Charter, specifically within the proposed scopes of Release 2 and Release 3. The table on the top of page 8 of the Program Charter outlines the timelines and the solutions enabled by Release:

- Release 2: Advisory FLISR - 2026-2027
  - This implementation would provide recommendations to operators for the steps required for fault isolation and service restoration, which helps reduce outage durations and improve system reliability.

- Release 3: Automated FLISR - 2028+.
  - This implementation would provide automation of steps required for fault isolation and service restoration without operator intervention, further reducing outage durations and improving system reliability.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-1

EVIDENCE REFERENCE:

JT2.6-ED-1

QUESTION(S):

JT2.6-ED-1 indicates that 43% of micro connections were connected within the prescribed timeframe and 57% were connected at a later, agreed-upon date. HOL indicated that "the later connection date reflected the customer's acceptance of, or request for, an appointment beyond the prescribed five days."Please provide an approximate breakdown of the instances where the connections occurred beyond the prescribed timeframe where (a) the customer accepted HOL's proposed later date versus (b) the customer themselves requested the later date. Also, please explain how HOL ensures the customer has a real choice as to whether to accept or reject a revised date (please explain and provide text from example communications)?

RESPONSE(S):

When reviewing call records, Hydro Ottawa realized that an error was made by erroneously including weekends and holidays in the original timeframe calculation and as such Hydro Ottawa makes the following correction to JT2.6-ED-1[1] with respect to the estimate for the percentage of projects connected within the prescribed timeframe versus those connected on a mutually agreed-upon date. Using exclusively business days, 61% of the micro connections were connected within the prescribed timeframe, and 39% were connected at a later, agreed-upon date. In total Hydro Ottawa reviewed 69 calls.

[1] In JT2.6-ED-1, Hydro Ottawa originally reported that 43% of micro connections were connected within the prescribed timeframe, and 57% were connected at an agreed-upon date.

When a customer contacts Hydro Ottawa to request a micro connection appointment, the call center handles these inquiries organically. Representatives discuss the project scope and timeline and identify whether a specific completion date is needed. If no date is initially requested, Hydro Ottawa proposes a completion date. Of the 39% of micro connections that were ultimately connected at a later mutually agreed-upon date, 38% were agreed after customer suggestion, and 62% were agreed at the suggestion of Hydro Ottawa.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-2

EVIDENCE REFERENCE:

JT2.6-ED-2

QUESTION(S):

JT2.6-ED-2 indicates that HOL is considering fast-switching devices that would improve reliability while also eliminating short circuit constraints in its system by allowing the bus-tie to remain open. This seems promising. What timeline could HOL meet with respect to (a) completing the feasibility and cost/benefit analysis, (b) making an investment decision either way, and (c) implementing this solution (if it is accepted)?

RESPONSE(S):

Hydro Ottawa intends on completing the preliminary feasibility study for the fast-switching protection devices for Ellwood MTS in 2026. Assuming a positive outcome for feasibility, Hydro Ottawa will complete the project level investment planning in 2027, i.e. project concept definition and evaluation through project scoring to determine the overall value of the initiative, as described in Section 5.3.2, Schedule 2-5-4 - Asset Management Process, page 106 - 111. Based on the project value, it would be considered for inclusion through the annual project optimization process starting in 2028, as outlined in Section 5.3.2 of Schedule 2-5-4 - Asset Management Process, page 112. As a result of the annual prioritization process, Hydro Ottawa is not able to determine a specific timing for the initiative, as it would be evaluated against competing projects through the optimization process on an annual basis.

Based on a preliminary assessment of the work required to implement this solution, once the project is initiated, it is expected to take 2 to 3 years to go from preliminary design to in service.

A best case scenario - positive feasibility and project selected to begin in the subsequent annual project prioritization, would outline the following timeline:

a) 2026 - Feasibility Assessment
b) 2027 - Project level investment planning and optimization
c) 2028 - Project Initiation
d) 2029/2030 - Energization

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-3

EVIDENCE REFERENCE:

JT2.6-ED-5

QUESTION(S):

JT2.6-ED-5 discusses how HOL will attribute/allocate meter replacement costs to DER customers. Please estimate what Hydro Ottawa would charge to the customer for a meter replacement where the existing meter is roughly the average age of Hydro Ottawa's meters (which is relevant for determining the remaining net book value). Please include all calculations, including HOL's estimate of the incremental cost of a dedicated truck roll versus replacement through the coordinated replacement strategy. Also, please confirm that, when HOL refers to "any costs associated with the dedicated truck roll and labour that would be required to replace the meter on a one-off basis rather than through a coordinated replacement strategy," it is referring to incremental costs, not the gross cost of a truck roll.

RESPONSE(S):

With regards to JT2.6-ED-5, there are three separate scenarios a customer may experience where the customer:

- is requesting a micro-generation connection (a new DER customer);
- requires installation of an AMI2.0 compatible bi-directional meter in an area that is supported by AMI 2.0 communications infrastructure; or
- requires installation of a conventional bi-directional meter installation in an area that is not yet supported by AMI 2.0 communication infrastructure.

To further illustrate the scenarios, it should be noted that the AMI 2.0 rollout is proposed to occur over a 10 year cycle, and it should be assumed that the roll-out will occur geographically across Hydro Ottawa's service territory. Furthermore, the roll-out assumes that all meter replacements during the AMI 2.0 are inherently not bi-diretional unless required. Those scenarios and the effective customer charges for an existing customer requiring a bi-directional meter as a result of a micro-generation installation are listed below.

Please also note that in the majority of scenarios, changing to a bidirectional meter outside the meter's typical cycle, will result in an additional truck role to that location over the expected life of the premise. In addition, as it's not part of a typical meter replacement cycle, any truck role will be to accommodate this customer specifically. For these scenarios, the cost of the truck roll is $268.09 for labour and $73.77 for trucking, for a total of $341.86 and includes just over 2 hours to travel, complete the disconnection and to install the new meter.

- Scenario 1: A customer request to install a bi-directional meter in an area where Hydro Ottawa is actively completing the AMI 2.0 rollout. The cost to the customer would be the incremental cost of the bi-direcional meter material exclusively above and beyond a standard meter, which under present rates, is [redacted].

- Scenario 2: A customer request to install a bi-directional meter in an area where Hydro Ottawa is not actively completing the AMI 2.0 rollout. However, the area allows for integration with the upcoming AMI 2.0 communications framework (given communication preparation of meter conversions in that geographical location), and the bi-directional meter to be installed suits the AMI 2.0 rollout. In the case where there is 0 net book value (NBV) remaining and 0 years of advancement cost, the customer charge would be the incremental truck roll of $341.86 plus the [redacted] incremental cost of the bi-directional meter, totalling [redacted], as indicated in Table 1 below. As many scenarios of remaining book value and advancement costs are possible, Table 1 below provides additional scenarios where remaining NBV and advancement costs are also considered.

- Scenario 3: A customer request to install a bi-directional meter is received in an area that is not ready for integration with the upcoming AMI 2.0 communications framework. In this scenario, Hydro Ottawa would be required to install an AMI 1.0 bi-drectional meter that will ultimately be incompatible with the AMI 2.0 platform when the AMI 2.0 rollout occurs in this area (note the meter cannot be used in the future when AMI 2.0 is implemented). In this scenario, the customer charge would be the advancement cost of replacing the meter, the incremental truck roll/labour to replace the meter, the remaining NBV as well as the incremental cost of the new bi-directional meter material itself. For this scenario, the sample costs in Table 1 would also apply, however the NBV could be greater than 5 years depending on the specific installation.

Calculation Description/Method:

Table 1 - Net Book Value and Advancement Timing of Meter Replacement

Net Book Value (Years)	Advancement Time (Years)	Bi-Directional Meter Replacement Cost ($)
0	0	[redacted]
0	5	$421
0	10	$466
5	0	$413
5	5	$476
5	10	$522

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-4

EVIDENCE REFERENCE:

JT2.6-ED-8

QUESTION(S):

JT2.6-ED-8 indicates as follows: "If an increase in service size does not translate into a change in peak demand it will not impact peak load forecasts since the forecast methodology is based on aggregated, measured peak demand. A service upgrade may, however, require local network upgrades based on load sizing as per the Canadian Electrical Code." Please elaborate on the final sentence, including how relevant that factor may become if electrification leads to accelerated panel replacements. This will help assess the potential benefits of helping customers adopt alternatives to panel upgrades.

RESPONSE(S):

The final sentence in JT2.6-ED-8 - noting that a service upgrade may require local network upgrades based on load sizing as per the Canadian Electrical Code (CEC) - highlights a key distinction between system-wide load forecasting and local capacity management. While a customer's service upgrade does not impact system peak load forecasts, which are based on aggregated, measured peak demand, Hydro Ottawa must still ensure that the physical capacity of its local infrastructure can safely handle the maximum potential load a customer is now legally permitted to draw under the CEC. This service size increase, often required for new electrification appliances, triggers a localized assessment that may necessitate upgrades to the local distribution transformer or the low-voltage network, such as cables. This local capacity management process is separate from load forecasting.

This factor becomes increasingly relevant if electrification leads to accelerated panel replacements, as it represents a localized impact that is independent of system-wide load growth and therefore not captured in peak demand forecasts. A local network upgrade is typically triggered if the service upgrade causes key physical component thresholds to be exceeded, such as the capacity of the secondary conductor, the number or size of services per transformer, or the distribution loop capacity. The likelihood of triggering an upgrade is highly variable due to the many unique configurations of Hydro Ottawa's distribution network (a result of the amalgamation of 5 utilities, each with separate network configurations). However, as noted in response to interrogatory 2-ED-12, conductors and transformers installed post-2019 are sized to accommodate electrification - specifically, a Level 2 charger at every home - and are not anticipated to need premature replacement. Therefore, the risk of triggering costly local upgrades due to panel replacements is concentrated in the older parts of the service territory that are not aligned with the updated standards like UKS0171. This localized risk is partially mitigated as end-of-life infrastructure replacement, which, as a standard practice, automatically brings older network components up to current Hydro Ottawa standards, thereby reducing the need for separate electrification-driven upgrades.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-5

EVIDENCE REFERENCE:

JT2.6-ED-11(e)

QUESTION(S):

JT2.6-ED-11(e) indicates that "the connection charge of $564.24 ... is the Customer Layout cost for micro connections." However, part (c) indicates that the "charge is for both the bi-directional meter and the associated labour for its installation." Please reconcile the statements, indicate what the $564.24 charge covers, and provide all assumptions and calculations indicating how the figure was developed. Please do not simply refer to Appendix G of the Conditions of Service, as it does not provide this information.

RESPONSE(S):

In Hydro Ottawa's response to part (e) of JT2.6-ED-11, the reference to "customer layout" is an all encompassing term for the costs associated with completing a micro-generation connection, including associated labour, trucking and material. The response in part (c) of JT2.6 is meant to clarify that the costs of completing a micro-generation connection include these items.

More specificity, the $564.24 encompasses: $268.09 for labour, $222.38 for material, $73.77 for trucking. This cost was determined through estimating the labour, material and trucking requirements associated with a generic connection, which was then reconciled using actual historical data. The above noted costs are considered incremental.

Please also see response to SC-ED-3 for multiple costs scenarios and calculations.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-6

EVIDENCE REFERENCE:

JT2.6-ED-11
JT2.6-ED-5

QUESTION(S):

Both JT2.6-ED-11 and JT2.6-ED-5 describe costs that will be charged to customers who need a net meter. Please confirm if the figure referenced in JT2.6-ED-11 will be updated to reflect the calculation in JT2.6-ED-5.

RESPONSE(S):

The figure referenced in JT2.6-ED-11 is an estimated cost for a micro-generation customer requiring a bidirectional meter. Given that various scenarios are possible for DER customers requiring a bi-directional meter, please refer to SC-ED-3 which provides multiple examples of cost estimates where advancement costs and a net book value are considered.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-7

EVIDENCE REFERENCE:

JT2.6-ED-13

QUESTION(S):

JT2.6-ED-13 indicates that HOL is not willing to take advantage of s. 6.2.24 of the DSC to lower DER connection costs. That section allows LDCs to agree to treat DERs with a capacity greater than 10 kW as micro connections. HOL indicates that its "simplified" process is sufficient to lower costs. However, the cost of a simplified connection is $7,000 versus $600 for a micro connection. This will make some DERs in the lower end of the small category range financially untenable (e.g. in the 10 kW to 30 kW range). Would HOL consider exploring something similar to the approach in the IREC Model Interconnection Procedures where DERs can be connected without a Connection Impact Assessment if they meet various screens and are below 25 kW exporting (see page 15 for the screens). We are not looking for commentary on a specific threshold or on whether HOL will adopt any of the recommendations, just commentary on whether HOL would explore this as a means to lower connection costs for DERs at the lower end of the small DER category range.

RESPONSE(S):

As mentioned in Undertaking JT2.6-ED-13, Hydro Ottawa is aware of Section 6.2.24 of the Distribution System Code, where Hydro Ottawa could agree in writing to apply the micro DER connection process to DERs above 10 kW. However, Hydro Ottawa has chosen not to exercise this option but rather follow the guidelines mandated in the OEB's DER Connection Procedure (DERCP) which requires a connection impact assessment for DERs > 10kW.

This is mainly due to the fact that not getting an opportunity to conduct an impact assessment poses several technical risks as follows:

- System Visibility: Lack of visibility of new DERs connecting to the grid.
- Monitoring & Control: Inability to implement necessary monitoring and control capabilities.
- Aggregated Impact: Unmanaged collective impact of DERs, which introduces protection, reliability, and planning challenges.
- Long-term Planning: Potential to hinder the implementation of non-wire solutions and other technology improvements in the long run.

Adhering to the DERCP also ensures consistency and fairness among similar applicants across the distribution system.

Due to this, Hydro Ottawa must respectfully decline to independently explore the IREC Model Interconnection Procedures or increase the DER capacity threshold for the micro connection process. Hydro Ottawa remains committed to supporting DER adoption and considers the Simplified Connection Impact Assessment process to be the appropriate mechanism for balancing connection cost with system operability needs.

This simplified process was determined after extensive brainstorming sessions with other Ontario LDCs within the OEB DER Working Group to define the best path forward. Consequently, any further simplification or change to the provincial connection process must be discussed and vetted through the OEB DER Working Groups to ensure feasibility for LDCs across the province and socialized and implemented via a formal amendment to the OEB's DERCP guidelines.

Hydro Ottawa will continue to actively engage with the OEB DER Working Groups to identify and implement practical improvements to connection practices province-wide.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-8

EVIDENCE REFERENCE:

JT2.6-ED-16

QUESTION(S):

JT2.6-ED-16 indicates that HOL is unwilling to even consider adopting Hydro One's approach of assessing the total lifetime cost of transformers and conductors, including the forecast cost of losses over the equipment lifetime, and selecting the least-cost option. HOL states that "The [CSA] standard, optimized for minimum total losses, is rooted in a least lifecycle cost analysis; applying it separately would result in double-counting the benefit." This double-counting comment does not make sense, at least on the surface. The CSA standard simply sets minimum efficiency levels. Please explain the sentence. Please also explain why Hydro One's least-lifetime-cost approach would make sense for that utility but not for Hydro Ottawa? We assume that Hydro One also purchases only CSA compliant equipment.

RESPONSE(S):

The minimum efficiency levels prescribed in CSA C802.1 are consistent with the cost-benefit analyses presented in the standard, which balance higher manufacturing costs against reduced lifetime energy losses. The manufacturers must design to meet or exceed C802.1’s minimum efficiency thresholds. This requirement inherently drives:

- Better core steel (to reduce no-load losses);
- Larger conductor cross-sections (to reduce load losses); and
- Improved winding design and cooling efficiency.

Compliance with CSA C802.1 requires manufacturers to minimize both no-load losses and load losses simultaneously. The efficiency metric itself incorporates the essential technical drivers that a total ownership cost analysis would incentivize. Therefore, performing a separate total cost of ownership is considered a form of double-counting the loss-reduction benefit that is already inherent to the minimum efficiency requirement.

When procuring distribution transformers, Hydro Ottawa cannot determine the specific site at which they will be installed in every scenario. The inherent efficiency requirements embedded within the application of the standard reflect an optimization equivalent to a total ownership cost approach, allowing for standardization. Therefore, for most procurement purposes, the efficiency standard serves as a practical guide to minimize no-load losses and load losses from distribution transformers, which ultimately lowers overall system losses.

Hydro Ottawa has no details with respect to the methodology, considerations or rationale applied by Hydro One for their decisions for transformer standardization. It therefore cannot comment on the applicability to Hydro Ottawa's system.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-9

EVIDENCE REFERENCE:

JT2.6-ED-17

QUESTION(S):

JT2.6-ED-17 discusses monthly MicroFIT charges. HOL proposes a charge that is more than two times other major distributors ($11 vs. $5). The undertaking response describes how HOL calculated its charge, but it does not indicate what unique factors apply to Hydro Ottawa but not to other major distributors, which would justify charges that are more than twice as high. Without that explanation, we can only assume that HOL should be able to reduce costs and charges to the levels of other major distributors. If that is not the case, please indicate the unique factors responsible for that, the assocated costs, and why those costs cannot be eliminated.

RESPONSE(S):

The Ontario Energy Board (OEB) initially established a province-wide fixed monthly charge for microFIT customers in 2010. This charge was set at $5.25 in 2010 and was determined using a customer-weighted average methodology based on nine defined administrative cost elements submitted by a group of local distribution companies across Ontario. Hydro Ottawa notes that the change between the original OEB-approved charge and the prevailing provincial rate of $5.00 cannot be commented on due to insufficient public data regarding the OEB's subsequent adjustments.

Hydro Ottawa has conducted a detailed assessment of the incremental costs associated with managing embedded micro-generator accounts. The proposed fee of $11.00 is designed to recover the expense of, on average, seven minutes of additional administrative labor per customer each month. This administrative time is dedicated to essential tasks, such as providing accurate generation data to the Independent Electricity System Operator (IESO) and guaranteeing the timely and precise processing, computing, and settlement of payments for all micro-generator accounts. The full calculation that supports this proposed charge can be found in Attachment 8-4-2(A) - Proposed Generation Charge Calculations.

Environmental Defence's assertion is inaccurate and appears to be premissed on the generic rate being based on other distributors' generation related costs. The generic rate is not based on generation specific costs and provides a proxy based on load customer billing. Specifically as part of the decision, the Board states "The Board considers all 9 cost elements to be appropriate at this time but expects distributors to maintain adequate tracking of activities specific to this new class of customer for a sufficient period of time so as to detect any ongoing material variants. [emphases added]" Hydro Ottawa has followed the board's direction and identified the overall cost difference between the method of a generic rate (mainly load customer costs) and a generation specific costs as directed.

Within JT2.6-ED-17 and the original evidence, Hydro Ottawa also indicated specific items that load customers and generator customers deviate specifically on in terms of processes and cost. For example, as noted in JT2.6-ED-17 only 60% of generation customers opt for electronic payment within Hydro Ottawa service territory while load customers exceed this level of embedded cost related to electronic invoices. In addition, 96% of Hydro Ottawa's vendors are paid by EFT, a significantly larger number than what is experienced with generators.

SETTLEMENT RESPONSES TO ENVIRONMENTAL DEFENCE

SC-ED-10

EVIDENCE REFERENCE:

JT2.6-ED-18

QUESTION(S):

JT2.6-ED-18 proposes to amend the MicroFIT tariff to read as follows: "This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program or other generation <10kW and connected to the distributor's distribution system." This appears to be too broad as it would appear to capture net-metering customers and load displacement customers. If that is incorrect, please explain why and please propose wording to clarify. Please consider something along the following lines: "This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's ("IESO") microFIT program or a subsequent IESO program, metered separately from the customer's load, and connected to the distributor's distribution system."

RESPONSE(S):

The amendment was intended to preclude both net-metered customers and load displacement customers where monthly service charges are already applied to the account as a load customer. Please see the adjusted draft language (in bold) to provide further clarity. This language would also be incorporated into the >10MW generation charges for clarity on charges to net-metered customers and load displacement customers.

Hydro Ottawa also made a clarification update to the >10kW generation charge similar to the previously requested clarification for <10kW.

MicroFIT AND OTHER GENERATION <10kW SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program or other generation <10kW and connected to the distributor's distribution system. **This charge would not apply to customers with generation who are considered a load customer within another rate classification that receive a monthly fixed service charge.** Further servicing details are available in the distributor's Conditions of Service.

FIT AND OTHER GENERATION >10kW SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's FIT program **or other generation >10kW (but does not meet the requirements of HCI, RESOP, OTHER ENERGY RESOURCE SERVICE CLASSIFICATION)** and connected to the distributor's distribution system. **This charge would not apply to customers with generation who are considered a load customer within another rate classification that receive a monthly fixed service charge.** Further servicing details are available in the distributor's Conditions of Service.

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-1

EVIDENCE REFERENCE:

JT1.14-VECC-6.6

QUESTION(S):

Please provide a copy or reference to the update.

RESPONSE(S):

Please refer to the update filed by Hydro Ottawa on October 24, 2025 which includes the following:

- JT1.14-VECC.6.6 - Updated October 24, 2025
  - Attachment JT1.14-VECC-6.0(B) - Revised 3.0-VECC-29
  - Attachment JT1.14-VECC-6.0(C) - Revised Large Load Electrification kW by Month (Excel file)
  - Attachment JT1.14-VECC-6.0(D) - Original Large Load Electrification kW by Month (Excel file)

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-2

EVIDENCE REFERENCE:

JT2.16

QUESTION(S):

With respect to Attachment A, please explain the reasons for the increase of $1,669k in the update to the 2025 OM&A forecast, specifically the increases in vegetation management, station maintenance and IT in 2025.

RESPONSE(S):

In Attachment JT2.16(A), the 2025 OM&A Forecast was updated with $120.6M, which exceeds the bridge year budget assumption of $118.9M by $1.7M. The most notable increases are in Vegetation Management, Stations Maintenance, and Information Management & Technology. Please see below for the specific drivers associated with the increases.

Vegetation Management saw an increase in costs as of 2024, as stated in interrogatory response 4-Staff-139, driven by inflationary pressures and labour competitiveness. This led to a rise in contractor pricing for the planned trimming program, as well as pricing increases for the as-needed and emergency programs. The updated pricing impacted both 2024 and 2025.

In addition to pricing increases, the as-needed program has seen an increase in the volume of customer-identified trimming needs as a result of leftover damage from the 2022 Derecho. The emergency program has been focused on removal of trees identified by the Overstory software as posing a high risk of interference with the distribution system in the event of a storm. This is part of

Hydro Ottawa's storm hardening efforts to reduce customer interruptions during severe weather events.

To offset the increased costs in the as-needed and emergency programs, Hydro Ottawa has scaled back its planned trimming program in areas of low risk to the distribution system and redirected the budget accordingly, which can be seen in Table A. This decision was informed by the analysis performed by Overstory to optimize spending and improve reliability, specifically by adjusting spans within or outside the scheduled vegetation management trim cycle. Hydro Ottawa plans to continue to pursue this approach for cost offsetting, ultimately leading to a more efficient deployment of planned trim cycles.

Table A - Vegetation Management Cost Breakdown ($'000s)

	Historical Years				Bridge Year	Forecast	Variance	Test Year
	2021	2022	2023	2024	2025	2025	2025	2026
Planned	$ 2,727	$ 2,551	$ 2,902	$ 3,324	$ 3,677	$ 3,152	$ (525)	$ 3,910
As-Needed	$ 706	$ 743	$ 1,264	$ 2,556	$ 1,650	$ 2,810	$ 1,160	$ 1,710
Emergency	$ 378	$ 3,426	$ 2,091	$ 1,055	$ 494	$ 1,102	$ 608	$ 528
Total	**$ 3,811**	**$ 6,720**	**$ 6,257**	**$ 6,936**	**$ 5,821**	**$ 7,064**	**$ 1,243**	**$ 6,149**

Stations Maintenance is forecasted above bridge year, as generally explained in 4-Staff-140 part (b). This increase stems from the following sources:

- Increased scope & station complexity: the inherent configuration of the 2025 stations within the preventative program required higher than typical planning and coordination, as well as an increase in scope associated with specific components at those stations. Furthermore, as a result of a general backlog in maintenance initially stemming from the 2022 Derecho and 2023 labour disruption, both 2024 and 2025 saw generally increased volumes above and beyond the baseline requirement for maintenance;
- Elevated Crew Sizing and Unit Labor Costs: crew requirements were above budgeted amounts, partly due to the broad addition of apprentices to the workforce, whereas

historically Hydro Ottawa has had a larger complement of journeypersons within its Stations tradestaff;

- Unexpected transformer relocations resulted in increased reactive spending; and
- Switching costs exceeded the budget primarily due to intricate load transfer plans, extensive job plan processing, and the actual switching and restoration tasks necessitated by the planned station work.

Information Management & Technology's forecast is above bridge year due to pricing increases in maintenance and subscription costs that were higher than was expected based on historical trends. As mentioned in part (e)(vii) of the response to interrogatory 4-Staff-150, software vendors have cited inflation and enhanced features (such as AI integration) as the basis for these increases.

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-3

EVIDENCE REFERENCE:

TC Day 2, p.139, lines 17-20

QUESTION(S):

Hydro Ottawa stated “for other reasons as we have outlined”, please indicate where this was outlined and what the other reasons were.

RESPONSE(S):

This question relates to the discussion during the technical conference regarding the increase in corporate cost allocations following the 2022 storm events and the 2023 labour strike. As noted in the transcript, Hydro Ottawa explained that while those events initially contributed to higher costs, the elevated level of corporate allocations has continued due to other ongoing factors.

The “other reasons” are outlined in interrogatory response 4-Staff-156 and in Section 4.1 of Schedule 4-2-1 - Shared Services and Corporate Cost Allocation. The other reasons include expanded capital programs and a growing customer base, along with broader factors such as an evolving regulatory environment, climate change impacts, and the ongoing digital transformation of the utility sector, all of which have contributed to increased corporate allocations.

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-4

EVIDENCE REFERENCE:

JT3.21

QUESTION(S):

This undertaking asked about Large Load electrification and the answer referred to JT1.14-VECC-6.0 part 6.2 which refers to disaggregation not electrification. Please clarify and provide the information requested in JT3.21.

RESPONSE(S):

Hydro Ottawa clarifies the response to JT 3.21 should have directed the reader to part 6.1 of JT 1.14-VECC-6.0, which was not available at the time this question was submitted.

The information requested in JT 3.21 was submitted as part of the updated to technical conference undertakings on October 24, 2025. Please refer to the updated response to JT 1.14-VECC-6.0, part 6.1, Attachment JT 1.14-VECC-6.0(C) and Attachment JT 1.14-VECC-6.0(D).

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-5

EVIDENCE REFERENCE:

JT3.22

QUESTION(S):

With respect to JT 3.22:

a. In the discussion before this Undertaking was assigned, there was agreement to provide "the driving factors behind the unit numbers". Please provide.
b. Please recalculate the 2026 billing units for unprocessed payment charge, reconnect at meter – regular hours and reconnect at meter – after regular hours based on a five-year trend not the average of 2021-2025. Please continue the trend in billing units for 2027-2030 (related Undertaking JT1.14-VECC-4.0).

RESPONSE(S):

a. Methodology and driving factors for the 2026 unit numbers were determined as follows:

   - **Unprocessed Payment Charge** units were determined using the average of the 2021-2023 Actual and 2024-2025 Bridge Years. The higher-than-normal volume of unprocessed payments observed over the past few years is partially explained by inflationary pressures. As the inflation rate pressures eases, this trend is not anticipated to continue.
   - **Reconnect at Meter - Regular Hours** units were determined using the average of the 2021-2023 Actual and 2024-2025 Bridge Years and then adjusted upward to 1,794. During the COVID years, the number of disconnections was reduced, leading to larger growth in

post-COVID years. This type of growth is not anticipated to continue. An average of the five years corrects the distorted trend.

- **Reconnect at Meter - After Regular Hours** units were determined using the average of 2022-2023. When estimating the 2026 unit volumes, the year 2021 was excluded as an outlier. Additionally, the years 2024 and 2025 were not used in the estimation because their initial volume estimates were determined to be overstated. For the same reason explained above, using an average corrects the distorted trend.

Please see Table A below for the units and the associated revenue for each of the three services requested. The unit forecasts for 2027-2030 were maintained at 2026 level as no additional analysis or assumptions were applied beyond the 2026 forecast.

Table A - Specific Service Charge Revenue and Occurrences [1, 2]

	Historical Years				Bridge Year		Test Years				
	2021	2022	2023	2024	2024	2025	2026	2027	2028	2029	2030
Unprocessed Payment Charge											
Units	2,391	2,653	3,175	3,383	3,521	3,739	3,096	3,096	3,096	3,096	3,096
Revenue ($'000s)	$ 60	$ 69	$ 86	$ 94	$ 99	$ 108	$ 77	$ 77	$ 77	$ 77	$ 77
Reconnect at Meter - Regular Hours											
Units	739	1,436	1,725	2,934	2,432	2,605	1,794	1,794	1,794	1,794	1,794
Revenue ($'000s)	$ 50	$ 99	$ 122	$ 214	$ 180	$ 198	$ 126	$ 127	$ 129	$ 133	$ 136
Reconnect at Meter - After Regular Hours											
Units	15	229	243	443	562	570	236	236	236	236	236
Revenue ($'000s)	$ 1	$ 24	$ 26	$ 47	$ 62	$ 66	$ 22	$ 23	$ 23	$ 24	$ 24

b. Table B below presents the 2026-2030 billing units projections for Unprocessed Payment Charge, Reconnect at Meter – Regular Hours, and Reconnect at Meter – After Regular Hours using an excel trend function derived from the historical 2021-2024 period. Hydro Ottawa believes this results in units that are too high for the reasons stated above.

[1] Units as per SEC-85 and JT1.14-VECC-4.0.
[2] Revenue as per Schedule 6-3-2 Specific Service Charge Revenue

1 **Table B - Requested Trend Method Specific Service Charge Occurrences**

	Historical Years				Bridge Year	Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Unprocessed Payment Charge										
Units	2,391	2,653	3,175	3,383	3,739	4,125	4,475	4,824	5,174	5,524
Reconnect at Meter - Regular Hours										
Units	739	1,436	1,725	2,934	2,605	4,114	4,802	5,489	6,177	6,864
Reconnect at Meter - After Regular Hours										
Units	15	229	243	443	570	687	817	946	1,076	1,206

2

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-6

EVIDENCE REFERENCE:

1-SEC-20; 2025 Benchmarking Calculations.

QUESTION(S):

SEC understands that Table C, Step 1, to show the impact of an adjustment to the PEG benchmarking results of just an update to the historical circulate kilometers (inclusion of secondary line kilometers). Please reconcile those results, with the inclusion of the secondary line kilometers in the OEB's 2025 Benchmarking Calculations.

RESPONSE(S):

The OEB's 2025 Benchmarking Calculations used one year, 2024, of secondary circuit kilometers. This is demonstrated in cells AP79 and AP80, the 2024 Line KM and 2023 Line KM, respectively, in the OEB Benchmarking Calculations tab "2024 Benchmarking Calculations". Hydro Ottawa's total Line KM goes from 6,282 in 2023 to 12,914 in 2024.

Hydro Ottawa's Table C, Step 1, results in response to 1-SEC-20, includes secondary circuit kilometers between 2002 and 2023. The inclusion has two effects: first, each annual efficiency score from 2013 onwards includes secondary circuit kilometers, and second, the average of total circuit kilometers (a business condition) includes secondary circuit kilometers in each year. As a result, the annual total circuit and average total circuit kilometers include Hydro Ottawa's complete historical data.

Hydro Ottawa's understanding is that the OEB will not restate or recalculate prior PEG results, which is why they only included the 2024 secondary kilometers.

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-7

EVIDENCE REFERENCE:

2B-SEC-60

QUESTION(S):

Please explain why the System Access Capex/ISA ratio for 2026 capex is ~51%, but for all other years it is 100%.

RESPONSE(S):

Hydro Ottawa interprets the evidence reference as 2-SEC-35.

The System Access Capex/ISA ratio is 51% for 2026 because $20.6M of capital expenditures budgeted for the year for the following three projects will not be completed in that year:

- DND Dwyer Hill Station Upgrade
- Hydro Road System Expansion
- Hydro Road Station

Since these projects are not yet complete, the spending remains as Construction Work in Progress, resulting in a lower ratio of Capex to In-Service Additions (ISA) for 2026.

However, some errors were discovered in the original Attachment 2-SEC-35(A) - Capital Expenditures - ISA Conversion. These are specifically within the System Access and System Service investment categories. As such, not all other years are at 100%. The Test Year of 2029, like

2026, is not at 100%. The error is an isolated presentation issue related only to how the information was captured on the request spreadsheet. The underlying data remains correct including the calculation of revenue requirement. Please see the revised table in Attachment SC-SEC-7(A) - Capital Expenditures - ISA Conversion.

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-8

EVIDENCE REFERENCE:

JT1.8 Updated
3-1-1 Attachment B, Table 1-2

QUESTION(S):

For common years where there are actuals for each, please explain why the actuals in Table A (JT 1.8 Updated) does not match the actuals in Exhibit 3-1-1, Attach B, Table 1-2.

RESPONSE(S):

Table A in updated undertaking response JT 1.8 details historical peak values reported for RRR 2.1.5.5 system peak with embedded generation. The values in Table 1-2 of Attachment 3-1-1(B) - Hydro Ottawa Long Term Energy and Demand Forecast are historical system peak values reported for RRR 2.1.5.5 without embedded generation.

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-9

EVIDENCE REFERENCE:

QUESTION(S):

For each year of the plan, please provide the average CCA rate for in-service additions for each category of spending (i.e. System Access, Renewal, Service, and General Plant).

RESPONSE(S):

The average CCA rate for in-service additions by category of spending (i.e. System Access, System Renewal, System Service and General Plant) per Test Year can be found below in Table A - Average CCA per Category per Test Year by Original In-Service Addition Year. The supporting calculations for Table A can be found in Excel Attachment SC-SEC-9(A) - Average CCA rates for 2026 - 2030.

Accelerated CCA has been included in the 2026 and 2027 Test Years. Accelerated CCA has not been included in the 2028 to 2030 Test Years because Accelerated CCA is legislated to end at the end of 2027 and the half year rule becomes applicable again. Please note that these average CCA rates shown in Table A below show the applicable average CCA rate by original in-service addition year. For example, a General Plant addition of $10M in the 2026 Test Year would have an average CCA rate of 29.60% resulting in CCA of $2.96M for 2026. The 2027 average CCA rate for this same General Plant addition of $10M (originally added in 2026) is 13.24% resulting in CCA of $1.324M for 2027. The 2028 average CCA rate for this same General Plant addition of $10M (originally added in 2026) is 9.41% resulting in CCA of $941K for 2028. The 2029 average CCA rate for this same General Plant addition of $10M (originally added in 2026) is 6.88% resulting in CCA of $688K for

2029. The 2030 average CCA rate for this same General Plant addition of $10M (originally added in 2026) is 6.41% resulting in CCA of $641K for 2030. The average CCA rates in Table A below could be used to approximate CCA in the in-service addition Test Year and subsequent Test Years.

The average CCA rates in Table A below can be used to estimate the annual average CCA by category. However, different assets in the same category may attract different CCA rates. For example, the General Plant category may include trucks with a CCA rate of 30% (Class 10) or computer software with a CCA rate of 100% (class 12).

1 **Table A - Average CCA Rate per Category per Test Year by Original In-Service Addition Year**

In Service Addition Year	Category	2026 Test Year Average CCA Rate (%)	2027 Test Year Average CCA Rate (%)	2028 Test Year Average CCA Rate (%)	2029 Test Year Average CCA Rate (%)	2030 Test Year Average CCA Rate (%)
2026 Additions	General Plant (GP)	29.60	13.24	9.41	6.88	6.41
	System Access (SA)	8.00	7.36	6.77	6.23	5.73
	System Renewal (SR)	10.10	7.30	6.65	6.09	5.59
	System Service (SS)	12.59	7.75	6.72	5.99	5.43
2027 Additions	General Plant (GP)	-	29.19	13.84	9.88	7.22
	System Access (SA)	-	7.84	7.22	6.65	6.13
	System Renewal (SR)	-	7.99	7.34	6.75	6.20
	System Service (SS)	-	15.82	8.38	6.77	5.80
2028 Additions	General Plant (GP)	-	-	16.70	22.46	9.85
	System Access (SA)	-	-	4.00	7.68	7.07
	System Renewal (SR)	-	-	3.99	7.66	7.04
	System Service (SS)	-	-	4.30	7.95	7.01
2029 Additions	General Plant (GP)	-	-	-	9.11	13.19
	System Access (SA)	-	-	-	4.00	7.68
	System Renewal (SR)	-	-	-	3.99	7.66
	System Service (SS)	-	-	-	6.56	10.53
2030 Additions	General Plant (GP)	-	-	-	-	21.37
	System Access (SA)	-	-	-	-	4.00
	System Renewal (SR)	-	-	-	-	4.00
	System Service (SS)	-	-	-	-	4.43

2

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-10

EVIDENCE REFERENCE:

2B-SEC-25
JT2.18(A)

QUESTION(S):

Please explain why the total in-service additions related to capital expenditures incurred during the plan term as shown in 2B-SEC-35 are for certain years/categories higher than the total in-service addition for that year shown in JT 2.18(A). See analysis.

RESPONSE(S):

Some errors were discovered in the presentation of the original Attachment 2-SEC-35, specifically within the System Access and System Service investment categories. Please see the revised table in Attachment SC-SEC-7(A) - Capital Expenditures - ISA Conversion.

SETTLEMENT RESPONSES TO SCHOOL ENERGY COALITION

SC-SEC-11

EVIDENCE REFERENCE:

1-SEC-7

QUESTION(S): Provide an updated version of the revenue requirement table in 1-SEC-7 with the latest forecast specifically including

- Capital updates re Greenbank and Cyrville confirmed in SC-CCC-2
- Change in cost of capital parameters issued by the OEB this week
- Updates (if any) flowing from the load forecast changes noted above

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RESPONSE(S):

Interrogatory 1-SEC-7 requested that Hydro Ottawa revise Table 11 from Schedule 1-2-3 - Business Plan to show for each year, the Forecast Load at 2025 Rates, instead of 'Forecasted Load at Prior Years Rates'.

The Table from interrogatory 1-SEC-7 has been updated in Table A below using the revenue requirement numbers as updated in the response to interrogatory 1-Staff-1. This update incorporates several subsequent adjustments:

- Initial Baseline Updates: Includes all updates as per interrogatory 1-Staff-1;
- Capital Updates: Integrates the updated capital additions confirmed in pre-settlement question SC-CCC-2;
- Tax/PILs: Reflects the updated PILs and updated capital contribution;
- Cost of Capital: Applies the OEB's 2026 cost of capital parameters; and
- Working Capital: The calculation does **not** reflect an update for working capital.

Table A provides updated revenue requirement, excluding the yearly revenue deficiency information.

Table A - Revenue Sufficiency/Deficiency ($'000s)

	2026	2027	2028	2029	2030
Return on Rate Base	$91,043	$102,337	$116,311	$127,276	$134,808
Distribution Expenses (not including amortization)	$140,010	$147,263	$154,891	$162,914	$171,353
Amortization	$66,117	$74,998	$82,894	$89,658	$96,089
Payment in Lieu of Taxes	$6,337	$3,770	$11,740	$12,700	$15,714
Other Expenses	$5,524	$5,030	$0	$0	$0
Service Revenue Requirement	**$309,032**	**$333,397**	**$365,835**	**$392,548**	**$417,964**
Less Revenue Offsets	$11,018	$10,697	$10,859	$11,123	$11,460
Revenue Requirement from Rates	**$ 298,014**	**$ 322,700**	**$ 354,976**	**$ 381,425**	**$ 406,504**

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-1

EVIDENCE REFERENCE:

PILs Capital Contribution
Ref. 1: JT 4.6, Table 4, p.5
Ref. 2: Exhibit 9, tab 1, Schedule 4, p.5

QUESTION(S):

a) Please confirm that Hydro Ottawa will claim accelerated CCA in its 2026 and 2027 tax return filings.

b) For accelerated CCA and immediate expensing CCA deduction, please explain, from cash flow perspective, how the timing of Hydro Ottawa's receipt of the tax relieves compare to the timing of the tax relives being passed to the ratepayers over the periods. Staff has prepared a table below showing different scenarios where the accelerated CCA can be treated in the test year's PILs along with the smoothing adjustment and account 1592 sub-account CCA changes. Please provide the following information:

- Provide the balance/amount for each cell in the table; please provide the estimated number(s) with assumptions if exact number cannot be derived.
- Please compare the rate impact of Hydro Ottawa's proposal with the rate impact of other scenarios (#1 to #3).

Scenario for PILs in the test year	Test Year's PILs Expense	Smoothing Adjustment	Account 1592 Sub-account CCA Changes
1) PILs in the test year do not use the accelerated rule for CCAs	Test year's PILs expense embeds the CCAs based on the legacy half-year rule; in addition, 2027 tax filing will be based on half year rule	No need to smooth, given that the CCAs in 2026 and 2027 are based on the half-year rule	Not applicable since the tax rule embedded in the rates is consistent with the tax rules in the actual tax filings
2) PILs in the test year use the accelerated rule for CCAs and do not apply the smoothing adjustment	Test year's PILs expense embeds the CCAs based on the accelerated rule; in addition, 2027 tax filing will be based on the accelerated rule.	Not applying the smoothing adjustment because Account 1592 sub-account CCA Changes is to be used for any cost recoveries	Account 1592 sub-account is to be used to record the revenue requirement impact from the tax rule difference between what is embedded in rates (accelerated in 2026) and the tax rule (half-year rule) in the years of 2028 till next rebasing application
3) PILs in the test year use the accelerated rule for CCAs and use the smoothing adjustment used by other utilities	Test year's PILs expense embeds the CCAs based on the accelerated rule; in addition, 2027 tax filing will be based on the accelerated rule. The calculated smoothing adjustment increases the PILs of the test year by adding the smoothing adjustment in the PILs	Smoothing adjustment is based on a calculation of one fifth of the forecasted balance in Account 1592 sub-account CCA changes for the period of 2028 till next rebasing application, using forecasted capital additions in the period	Account 1592 sub-account CCA changes is not needed in the rate term and could be closed.

Scenario for PILs in the test year	Test Year's PILs Expense	Smoothing Adjustment	Account 1592 Sub-account CCA Changes
	model for the test year.		
4) PILs in the test year use the accelerated rule for CCAs and use the smoothing method proposed by Hydro Ottawa	Test year's PILs expense embeds the CCAs based on the accelerated rule; in addition, 2027 tax filing will be based on the accelerated rule. The impact of the accelerated CCA rule in PILs is offset by an equivalent increase in the PILs contribution recorded under Other Expense	Smoothing adjustment is based on the proposed PILs contribution which is proposed to be treated similarly to Capital Contributions in the fixed asset subledger and to be amortized over 36 years to smooth out.	Account 1592 sub-account CCA changes is not needed in the rate term for the purpose of the current accelerated CCA rule.

RESPONSE(S):

a) Confirmed. If Hydro Ottawa did not claim Accelerated CCA in its 2026 and 2027 tax returns there would be no underlying need to provide it back to customers. Hydro Ottawa's PILs contribution proposal is being proposed to match the benefit of Accelerated CCA to the depreciation cost of the asset in order to reduce intergenerational issues.

b) As Hydro Ottawa indicated in the original evidence and within JT4.6, Hydro Ottawa's proposal is not to simply smooth rates over 5 years as a result of the impact on an IR rate period or some other time period. The proposal is instead to manage the intergenerational issues of

Accelerated CCA. Hydro Ottawa's proposal is to dispose of the balance through a PILs contribution.

Board staff indicated questions put forth as part of Pre-Settlement proceedings were for clarification purposes. As a result it is unclear if the scenarios presented are a result of Board staff's assumption that the response to part(a) would not be confirmed, especially given scenario one, or if these scenarios instead are intended to introduce new scenarios not previously discussed. Specifically, the scenarios appear to shift to a one year cost of service methodology with uncertainty if an escalation factor is applied. Lastly, please note Hydro Ottawa finds some of the wording in part (b) of this question unclear. As such, this may have resulted in further uncertainty to the intent of the request.

Scenario 1 is not a practical nor applicable scenario. For clarity, as per response to part (a), Hydro Ottawa plans to apply Accelerated CCA in the actual tax returns for 2026 and 2027.

There is no rationale for Hydro Ottawa not to calculate and to deduct Accelerated CCA for 2026 and 2027 Test Years as allowed by time limited Federal Income Tax legislation. Accelerated CCA in the 2026 and 2027 Test Years as included in base rates for 2026 and 2027 Test Years decrease PILs expense for those years and regardless of timing of how the benefit is incorporated into revenue requirements, it is beneficial to customers if interest (at a minimum) is applied. The issue being contemplated in Hydro Ottawa's proposal is which customer will receive the benefit, i.e. mainly those in this 5 year period or matching to the customers who pay for the associated depreciation cost over the life of the assets.

Removing Accelerated CCA from the 2026 and 2027 Test Years would increase PILs expense for those years and would equal to the proposed PILs amount plus the contributed PILs as presented in the response to interrogatory 1-Staff-1. This scenario would increase rates to customers in comparison to Hydro Ottawa's proposal, as customers will not receive the benefit of the reduction to rate base and the associated reduction in cost of capital. In addition, the intended cash flow benefit related to the tax benefit would be lost.

The description of Scenario 2 is not entirely clear to Hydro Ottawa. The premise appears to be that Hydro Ottawa uses one Test Year for the purpose of PILs and appears not to use the five year capital data to calculate proposed revenue requirement. If this is correct, it is unclear if an escalation factor is being suggested. In addition, it appears to use Account 1592 to smooth the impact of Accelerated CCA related to 2026. Lastly, only 2027 is mentioned as using Accelerated CCA for actual tax purposes, specifically it is unclear the expectation for 2026.

Overall it is not clear to Hydro Ottawa what is being suggested and this scenario appears to be requesting a completely different approach than contemplated in the application or discovery to date. If this is the case, the scenario does not address other PILs related adjustments over the custom period that would need to be contemplated if such a method was used. Given Hydro Ottawa does not fully understand what is being requested and if further assumptions are required, including the potential disconnect to the five year capital forecast, Hydro Ottawa is not able to speak to the impacts.

Scenario 3 is also unclear to Hydro Ottawa. It both states 1) Account 1592 forecasted balance will be used in 2028, and 2) 1592 is not needed in the rate term. In addition, it is unclear what forecasted balance would be in 1592 given only one fifth would apply for rate smoothing in 2028-2030. It is also unclear what 2027 to 2030's base PILs are. As with scenario 2, this approach appears to overcomplicate the treatments of Accelerated CCA when both five year capital forecast and five years of PILs models have been provided. As noted, Hydro Ottawa was not proposing a smoothing mechanism over 5 years but a proposal to minimize an intergenerational issue related to Accelerated CCA. This proposal is distinct from Hydro Ottawa's proposed PILs calculation, which was not suggesting a smoothing mechanism to manage the end date of Accelerated CCA. As with scenario 2, additional assumptions are missing.

This scenario appears to be trying to manage concerns of smoothing adjustments discussed and approved by the OEB for other utilities as outlined in the response to undertaking JT4.6. This smoothing adjustment allows utilities within the IR term to smooth out the increase in PILS when Accelerated CCA is no longer applicable within the IR term. Hydro Ottawa is not proposing to smooth out the increase in PILs when Accelerated CCA is no longer available, which is in the 2028 Test Year. Hydro Ottawa's proposed 2026 and 2027 include Accelerated CCA in base rates while 2028 to 2030 proposed PILs do not include Accelerated CCA in base rates.

Hydro Ottawa is not able to speak to the impacts of Scenario 3 given it is uncertain of how to approach the adjustments.

Scenario 4 appears to present a mechanism to address the intergenerational issues of Accelerated CCA in a different way. However this scenario is also unclear to Hydro Ottawa.

For the 2026 and 2027 Test Years, Accelerated CCA has been included in revenue requirement, however it is unclear what 2027 PILs is based on. It speaks to a smoothing mechanism but it is unclear how 2028-2030 removes the impact of Accelerated CCA, given it appears to imply all years will be set on 2026 and Hydro Ottawa maintaining the 2027 Accelerated CCA keeps the utility whole.

Hydro Ottawa is not able to speak to the impacts given the request is unclear to Hydro Ottawa.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-2

EVIDENCE REFERENCE:

Ref. 1: JT 4.6, Table 4, p.5
Ref. 2: IRR ATT 1-Staff-1(N) 2026 Revenue Requirement Workform_20280818, Tab 9, Cell N20
Ref. 3: Undertaking Responses, IRR ATT 1-Staff-1(N) 2027 Revenue Requirement Workform_202151007, Tab 9, Cell N20

Preamble:

OEB staff notes variances between the PILs contribution reported in the 2026 and 2027 Revenue Requirement Workforms and the total grossed-up PILs difference amounts reported in Reference 1. The variances, as calculated by OEB staff, are summarized in the table below.

PILs Contributions ($000s)	2026	2027
Ref. 1: Total Grossed Up PILs Difference	(5,484)	(4,727)
Ref. 2: Other Expenses Reported in 2026 RRWF	(5,066)	
Ref. 3: Other Expenses Reported in 2027 RRWF		(4,096)
Variances	(418)	(631)

QUESTION(S):

a) Please confirm the variances observed by the OEB staff and provide updated

2026 and 2027 Revenue Requirement Workforms, if applicable.

RESPONSE(S):

a) The figures in Ref 2 and Ref 3 from the 2026 and 2027 Revenue Requirement Workforms (RRWF) represent the preliminary grossed-up PILS amounts, as detailed in Schedule 9-1-4 - Account 1592 and Tax Variance, Section 7.

Through technical conference undertakings, Hydro Ottawa was requested to file updated Capital Cost Allowance (CCA) schedules to reflect the updated evidence provided in 1-Staff-1 (values for Ref 1). Undertaking response JT4.5 subsequently clarified that the updated PILS contribution amounts had not been reflected in revenue requirement, which accounts for the variances detailed in the preamble above.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-3

EVIDENCE REFERENCE:

Ref. 1: JT 3.27 (B), Tab 2021 Approved, Cell G43
Ref. 2: JT 3.27 (B), Tab 2021 Actual, Cell G43
Ref. 3: JT 3.27, Table G, P. 10

Preamble:

OEB staff notes discrepancies between the over-additions reported in Reference 3 and those calculated by OEB staff based on Reference 1 and Reference 2. The OEB staff calculation is provided in the table below.

	System Access: Residential & Plant Relocates
Ref. 1: 2021 Approved Additions	6,229,634
Ref. 2: 2021 Actual Additions	12,512,898
(Under)/Over Additions	6,283,264
Over Additions Reported in Ref. 3	6,431,000
Variance	(147,736)

QUESTION(S):

a) Please confirm the immaterial variance noted by the OEB staff.

b) If confirmed, please update the next time the schedule is submitted.

RESPONSE(S):

a) The immaterial variance of $148K noted by the OEB staff is a result of the difference between the regulatory versus tax basis of accounting. The amount on JT 3.27, Table G, P. 10 (Ref 3) is correct; the over additions for System Access (Residential & Plant Relocates) is $6,431,219 for regulatory accounting purposes. The 2021 actual additions in JT 3.27 (B), Tab 2021 Actual, Cell G43 of $12,512,898 (Ref 2) is also correct for tax accounting purposes. The actual fixed additions for regulatory accounting purposes and the actual fixed asset additions for tax accounting purposes may differ. The difference in 2021 additions for System Access Capital Additions (Residential & Plant Relocates) has been reconciled in the Table A below.

Table A - Variance in Actual Additions for Regulatory Accounting Purposes & Actual Additions for Tax (CCA) Purposes for 2021 ($'000s)

	System Access: Residential & Plant Relocates
2021 Actual Additions for Tax (as per CCA schedule) (Ref 2)	$12,513
Add back : SR&ED expenses expensed for tax capitalized for accounting[1]	$148
2021 Actual Additions for Accounting	$12,661
Less : 2021 Approved Additions (Ref 1)	$6,230
(Under)/Over Additions (Ref 3)	$6,431

b) Please see response to part a) above. Undertaking JT 3.27 and associated Attachments do not need to be updated.

[1] This represents current year SR&ED expenditures capitalized for accounting purposes but expensed for tax purposes. SR&ED expenditures are considered current expenditures for tax purposes.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-4

EVIDENCE REFERENCE:

QUESTION(S):

In response to 4-Staff-136(d), Hydro Ottawa states it “considered OM&A costs associated with staffing when completing the Benefit-Cost Analysis (BCA) provided in Attachment 2-Staff-67(A)”. Please clarify if all OM&A costs associated with the Non-Wires Customer Solutions Program (NWCSP) in Kanata North are fully captured under the 2026-2030 OM&A costs ($735,000) mentioned in Table 6 as well as in all DST and EST calculations of the BCA provided for the NWCSP in Kanata North (IRR 2-Staff-67(A)) - Benefit-Cost Analysis Summary Report.

a. Can you confirm that all OM&A costs associated with delivering the NWCSP in Kanata North, excluding customer incentives, is captured under the $2.8M annual budget/$13.4M 2026-30 budget under “Non-Wires Programming & System Integration” under the Testing, Inspection & Maintenance OM&A program?

RESPONSE(S):

Based on the clarified understanding of what constitutes incremental costs, discussed in more detail below, Hydro Ottawa confirms that there are no additional OM&A costs associated with the Non-Wires Customer Solutions Program (NWCSP) beyond those included in Table 6 of Interrogatory Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report.

Per the Benefit Cost Analysis (BCA) Framework, only incremental benefits and costs are to be included in a BCA. Hydro Ottawa understands “incremental costs” to be those costs that are new, additional, and directly attributable to the development and implementation of a specific initiative, and that would not have been incurred absent that initiative. In the context of NWCSP, this means that incremental staffing costs only arise where the work required to support NWCSP cannot be accommodated within existing staff capacity or responsibilities, or where reassignment of existing staff would require backfilling to maintain core operational service levels.

The OEB has previously emphasized this in other recent regulatory contexts, such as the implementation of Ultra-Low Overnight (ULO) rates. In that case, incremental staffing costs were recognized only where a utility was required to hire new or temporary staff to complete one-time CIS changes because existing staff could not absorb the work. Conversely, where utilities are able to reprioritize work for existing staff, no incremental staffing costs were recognized.

Applying this framework based on precedent set by the OEB, Hydro Ottawa would only identify staffing costs related to the NWCSP in the BCA if new personnel were required, or backfilling of redeployed staff was required to preserve core operational functions. ~~As noted in section 9.2.2.1 of Schedule 2-5-4 - Asset Management Process,~~ Although Hydro Ottawa has dedicated staff already in place to support the development and deployment of the NWCSP strategy, ~~This support includes assisting customers in identifying and developing potential projects in targeted areas of need, as well as leveraging existing customer relationships and communication channels for awareness and promotion of the NWCSP.~~ ~~E~~existing staff are not being treated as incremental OM&A. As such, these costs have not been included in the referenced Table 6 within Attachment 2-Staff-67(A)-NWCSP-BCA Summary Report, nor included in the BCA calculation. For clarity, these existing staff support includes assisting customers in identifying and developing potential projects in targeted areas of need, as well as leveraging existing customer relationships and communication channels for general awareness and promotion of the NWCSP.

Hydro Ottawa's existing team will be responsible for the design and delivery of the NWCSP. Of note, within pre-settlement response SC-VECC-10, Hydro Ottawa states that while most of the existing staff's time is dedicated to developing and deploying the NWSCP strategy and supporting customers interested in local energy efficiency initiatives, they are also involved in other non-NWSCP activities.

a) Hydro Ottawa confirms that all OM&A costs included in Table 6 of Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report are captured under the $2.8M annual budget/$13.4M 2026-2030 budget under “Non-Wires Programming & System Integration” under the Testing, Inspection & Maintenance OM&A program. However, for the reasons outlined above, costs associated with existing staff who will be supporting the NWCSP strategy are not captured in this OM&A program. As noted in Schedule 1-3-1 - Rate Sett~~l~~ing Framework, the 2026 year also includes external funding. The net effect from these two items can be seen in Table 11 of the same schedule. Hydro Ottawa does however acknowledge an omission within Table 10 of Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report. The Operations, Maintenance, and Administrative (OM&A) Costs were inadvertently excluded within the estimated DST costs line item of the table. Table A below provides the corrected version of Table 10, including the OM&A costs within the “Estimated DST Costs” row. Please see below for an updated Table 10 - Shared Savings Mechanism Calculation ($’000s) that was originally filed in Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report on August 18, 2025.

Updated Table 10 (Originally Filed in Attachment 2-Staff-67(A)) - Corrected Shared Savings Mechanism Calculation ($’000s)

	2026	2027	2028	2029	2030
Estimated DST Benefits	$ 297	$ 632	$ 783	$ 1,222	$ 1,282
Estimated DST Costs	~~$ 128~~ $ 373	~~$ 251~~ $ 496	~~$ 395~~ $ 640	$ 695	$ 749
Estimated Net DST Benefits	**~~$ 128~~ $ (76)**	**~~$ 251~~ $ 136**	**~~$ 388~~ $ 143**	**$ 527**	**$ 533**
Estimated Net DST Benefits (Capped at value of estimated DST Costs)	**~~$ 128~~ $ (76)**	**~~$ 251~~ $ 136**	**~~$ 388~~ $ 143**	**$527**	**$533**
NPV of estimated Net DST Benefits	**~~$1,486~~ $985**				
SSM (50%/50%)	**~~$743~~ $492**				

Please also see Attachment SC-Staff-4(A) - Updated Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report and Attachment SC-Staff-4(B) - Updated Attachment 2-Staff-67(A) - Appendix A - NWCSP BCA Summary Report.

Non-Wires Customer Solutions Program

Benefit-Cost Analysis Approach & Summary Report
West 28kV (North)
November 11 2025

Hydro Ottawa

1. EXECUTIVE SUMMARY

This report summarizes Hydro Ottawa's approach to applying the Ontario Energy Board's (OEB) Benefit-Cost Analysis (BCA) Framework[1], referenced within the Non-Wires Solutions Guidelines for Electricity Distributors[2], to determine the value of delivering Hydro Ottawa's Non-Wires Customer Solutions Program (NWCSP) in a targeted area of system need.

The NWCSP is targeted to provide immediate risk mitigation for capacity constraints through peak demand support until the required wires solution (new substation: "Kanata North MTS") can be energized. In addition, this region has been identified, through regional planning[3], to be restricted by transmission system constraints.

The NWCSP will be deployed in the Kanata area, effectively supporting the West 28kV (North) regional needs, and extend into portions of the West 28kV region (Bridlewood MTS and Terry Fox MTS), due to the interconnected nature of the systems through the communities they serve. As the specific needs are in the West 28kV (North) area supplied by Marchwood MTS and Kanata MTS, these two stations were the focus of the analysis. Based on the interconnected nature of these two stations with Bridlewood MTS and Terry Fox MTS, Hydro Ottawa will deploy the NWCSP to the Kanata Area for two purposes: A larger deployment area will help accelerate the acquisition of capacity at the constrained stations and broaden customer accessibility while aiming to minimize customer confusion (around eligibility) along the borders of the stations service areas.

The lessons learned through the NWS programming deployment in the Kanata area will inform Hydro Ottawa's approach to evaluating future applications of NWS.

Hydro Ottawa's NWCSP proposes to deploy six programs across all customer classifications:

1. Commercial Retrofit Incentive Adder Program
2. Residential Demand Response Program
3. Commercial Demand Response (HVAC) Program
4. Residential Solar and Battery Storage Adder Program
5. Commercial Solar Adder Program
6. Commercial Battery Storage Program

Where applicable, the customer-facing programs listed above are intended to build upon (through stacking incentives) existing Save on Energy programs funded by the Independent Electricity System Operator (IESO)

[1] https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/bca-framework
[2] https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/nws-guidelines-electricity
[3] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Ottawa/Ottawa-Area-20250731-IRRP.pdf

and are already available to Hydro Ottawa customers. Hydro Ottawa originally contemplated a portfolio of four programs, however, during additional analysis, it became clear that the Solar PV and Energy Storage Program concept should be further divided into 3 individual programs (items 4-6 in the list above), separating offers for residential customers and commercial customers. This configuration more closely aligns with the Save on Energy programming announced as part of the eDSM framework.

Through an NWS pre-assessment, Hydro Ottawa determined that the Kanata area (West 28kV (North) planning region) met the criteria for Scenario 1 and 3 of Hydro Ottawa's NWS Assessment Process. Additional detail on the process is found in Section 3.2.

In the short-term (2026-2028) while design and construction of a new station in the Kanata area occurs, Kanata North MTS, the analysis shows that the NWCSP - with a total estimated maximum capacity of 12.7MW acquired through 2028 - can be effective in minimizing the frequency, magnitude and duration of station loading beyond planning rating.

In addition, the BCA shows that the portfolio of programs can be effective in lowering peak demand after 2029 by offsetting energy system peaks, potentially deferring Hydro Ottawa's investment in a second new station. However this is premised on additional load being organic growth without the need to supply new large load requests (e.g., driven by electrification, data centres, or customer specific requests) for which Hydro Ottawa will have better visibility during the 2026-2030 period.

1.1. RESULTS

Table 1 summarizes the results of the BCA, including the Distribution Service Test (DST),the estimated Energy System Test (EST) and Net Present Value (NPV) of both.

Table 1 - BCA Results ($'000s)

BCA Result for NWCSP	
Total DST Benefit	$23,076
Total DST Cost	$15,064
NPV Net DST Benefit	**$8,012**
Total MW (2028)	**12.73**
Total EST Benefit	$85,184
Total EST Cost	$33,332
NPV Net EST Benefit	**$51,851**

1.1.1. Distribution Service Test Results

The Distribution Service Test (DST) calculates benefits and costs to the distribution system. For this analysis the approach adapted a formula from the BCA Framework to estimate benefits derived from comparisons of peak kilowatt demand before and after NWS deployment using an estimated marginal distribution cost of avoiding and deferring future investment in station and distribution capacity. This approach is further explained in Section 4.

The combination of the six programs modeled as a portfolio produces a positive Net Present Value of Distribution Service Benefits of $8M. This represents a funding request by Hydro Ottawa of $6.66M (refer to Table 6).

1.1.2. Energy System Test Results

The Energy System Test (EST) includes benefits and costs to the broader energy system, including upstream benefits from avoided transmission capacity, avoided generation capacity, and avoided energy consumption during winter and summer.

As presented in Table 1, the combination of programs modeled as a portfolio would produce a Net Present Value of Energy System Benefits estimated at $51.85M. This amount is additive to the NPV of Distribution System Benefits.

Energy system benefits, including generation capacity, avoided winter and summer on-peak energy and avoided transmission costs, are significantly larger than distribution service benefits. This is inline with previous work completed by the IESO, however calculations have not yet been shared with or assessed by the IESO.[4]

2. METHODOLOGY

The OEB prescribes Non-Wires Solutions Guidelines and a Framework for Benefit-Cost Analysis which has informed the methodology to estimate the outcomes from NWCSP.

Data used for modelling included hourly historical feeder and customer meter data for 2023 and 2024 and available data from previously operated Hydro Ottawa local programs (Kanata North Retrofit+). Assumptions for individual programs were made for future program uptake based on Hydro Ottawa's historical experience

[4] This is consistent with the finding in the IESO DER Potential Study Report and Recommendations, "The financial benefits associated with transmission deferral was found to be much larger than the distribution deferral opportunity, with the transmission deferral value representing 96% of the T&D avoided costs under all scenarios".
https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derps/derps-20220930-final-report-volume-1.pdf

with delivering similar programs. Feeder and system load forecast assumptions relied on hourly forecast information from Hydro Ottawa's Decarbonization Study[5].

As discussed earlier, the BCA comprises two separate and distinct cost-effectiveness tests: the DST and the EST. The DST analyzes costs and benefits exclusively for the distribution system. The EST estimates the costs and benefits exclusively for the energy system (including transmission, generation capacity, and energy costs).

Distribution service benefits, for the purpose of the analysis, are estimated using the annualized cost of avoided distribution capacity infrastructure based on an average of historical and forecast of Hydro Ottawa station and distribution infrastructure costs. This is described in further detail in Section 4 of this report.

Energy system benefits are estimated based on values published by the IESO as part of its Annual Planning Outlook (APO) in 2025[6] (for summer and winter peak hours as defined in the APO). Energy system benefits include avoided transmission capacity costs, avoided generation capacity costs, and avoided energy consumption. This is described in further detail in Section 5 of this report.

The outline of the subsequent headings in section 2 is intended to follow the sequence contained within the BCA Framework (i.e. "what to include"[7]) and reflect priorities of the NWS Guidelines[8].

2.1. FORWARD-LOOKING UNCERTAINTY

The OEB's BCA Framework requires distributors to explicitly address forward-looking uncertainty within their analysis. Through that lens and recognizing there are uncertainties associated with government policies and technological advancements that will impact future system requirements, Hydro Ottawa leveraged the Integrated Regional Resource Plan (IRRP) forecast derived from the Decarbonization Study to inform the reference case (reference case). The methodology is further detailed in Section 3.1 of this report.

2.2. DIFFICULT TO QUANTIFY AND QUALITATIVE IMPACTS

The BCA Framework describes quantitative and qualitative categories of benefits and costs. The present analysis focuses on specified quantitative benefits and costs. Where qualitative benefits potentially exist, they are detailed in Section 4.1.2 below.

[5] Hydro Ottawa Decarbonization Study - Final Report, 15 October 2024
[6] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[7] BCA Framework section 3.1 Page 9.
[8] NWS Guidelines, page 10: "General Evidentiary Requirements for Non-Wires Solutions".

2.3. SYMMETRICAL TREATMENT

For both the DST and the EST, treatment of benefits and costs are symmetrical - costs follow benefits. Hydro Ottawa has outlined its methodology to calculate benefits and detailed costs for each test in detail within Section 4 (DST) and Section 5 (EST). The methodology made use of the reference case scenario described in Section 4.1. DST benefits are calculated based on their maximum contribution to peak demand reduction, whereas the EST is calculated from kW reductions during winter/summer peak hours as defined by the IESO.

2.4. INCREMENTAL ANALYSIS

The BCA considers only impacts (benefits and costs) incremental to the reference case described in Section 3.1, which captures the business-as-usual outcome. For example, previously existing NWS capacity (e.g., existing rooftop solar PV) has not been included as incremental given that capacity is already reflected in the reference case.

2.5. NET PRESENT VALUE/DISCOUNTED CASH FLOW ANALYSIS

Per the OEB Guidelines, "to allow for a consistent approach to the valuation of NWS between regional and distribution system planning, electricity distributors are to use a real social discount rate of 4% for discounting cash flows to present value, and an assumed inflation rate of 2% for conversions between nominal and constant dollars[9]". All capital expenditures and incentive costs in the analysis are annualized using 2024 dollars, a 6% discount *rate* and a 25 year *term* so they can be expressed on an equivalent *annualized* $/kW-year basis, and for comparison with the IESO-published energy system avoided costs.

2.6. DISCRETIONARY VS NON-DISCRETIONARY SYSTEM NEEDS

As outlined within the BCA Framework, a discretionary system need is one with a reference scenario where doing nothing is an option. This is not the case for the needs identified within the West 28kV (North) planning region. The targeted stations are operating near or above planning limits and exceedances are forecasted to increase in frequency, magnitude and duration in the near-term (2026-2028) as well as the longer term. "Do-nothing" is not a viable option and the system need described herein is non-discretionary.

2.7. STUDY PERIOD

The study period considered for this analysis is 25 years, and the load forecast used values from 2026 to 2050, aligned with the Decarbonization Study's timeframe as well as the IESO's APO. A 25-year period is sufficiently long to capture the costs and benefits under comparison.

[9] OEB BCA Framework, p.13

2.8. TRANSPARENCY AND VALIDATION

Assumptions and sources of data are detailed within the required BCA workbook attached to this report as Appendix A.

3. DESCRIPTION OF DISTRIBUTION SYSTEM NEED BEING SERVED

3.1. REGION OVERVIEW

The West 28kV (North) region - the focus of this analysis and shown in Figure 3 below - includes the areas that are supplied by Kanata municipal transformer station (MTS) and Marchwood MTS in Kanata North which are well interconnected with each other. Rapid growth in Kanata North, particularly in the technology sector, has strained existing West 28 kV (North) stations, pushing them to their operational limits. There has been a surge in large load requests in this region and data center connection inquiries.

To address this demand and improve contingency preparedness, a new station ("Kanata North MTS") is under construction. This station will improve capacity, and support in reducing the impact of outages. Projected for completion in 2028, it will have two 100 MVA transformers and eight distribution feeders.

There is no further feasible wire solution capable of addressing this region's needs prior to station energization.

3.2. NWS PRE-ASSESSMENT

Hydro Ottawa has three scenarios used for assessing the viability of NWS in addressing system needs, two of which (Scenario 1 and Scenario 3) apply to West 28kV (North), as detailed in Table 2.

Table 2 - West 28kV (North) NWS Pre-Assessment Criteria

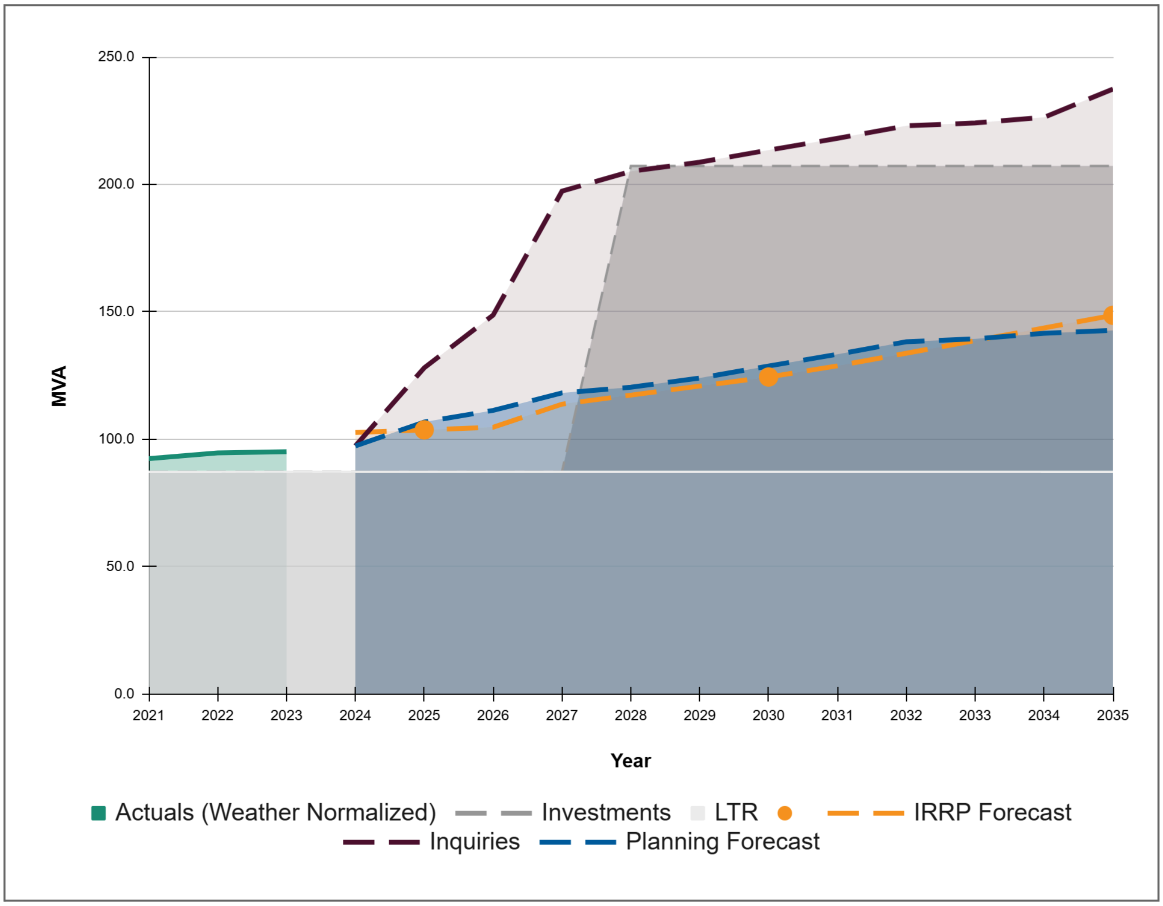
NWS Pre-Assessment Criteria						NWS Pre-Assessment Scenario?			NWS Pre-Assessment Scenario Pass?
Immediate Capacity Need?	Distribution Connected Station(s)?	Overload <7.5MVA by 2030?	Limited Connections?	IRRP Forecast overload by 2030?	Transmission Constraints?	Scenario 1	Scenario 2	Scenario 3	
✔					✔	✔		✔	✔

Scenario 1: Stations Requiring Capacity Risk Mitigation in the Near-Term

This scenario applies to stations that are currently facing capacity constraints and require immediate risk mitigation measures until a permanent wire solution can be implemented. This may be due to an inability to transfer loads to nearby stations or due to anticipated additional capacity needs in the near term. In these cases, NWSs can manage demand and ensure reliable service while the necessary grid infrastructure upgrades are being planned and constructed.

Figure 1 presents the load forecast for the West 28kV (North) region against planned capacity (LTR), factoring the energization of Kanata North MTS in 2028, which will increase the region's capacity to 207 MVA. The figure compares the IRRP Forecast, Planning Forecast, and the customer load inquiries which are in the planning stages in the West 28 kV (North) system.

Figure 1 - West 28 kV (North) Forecast with Kanata North MTS upgrade



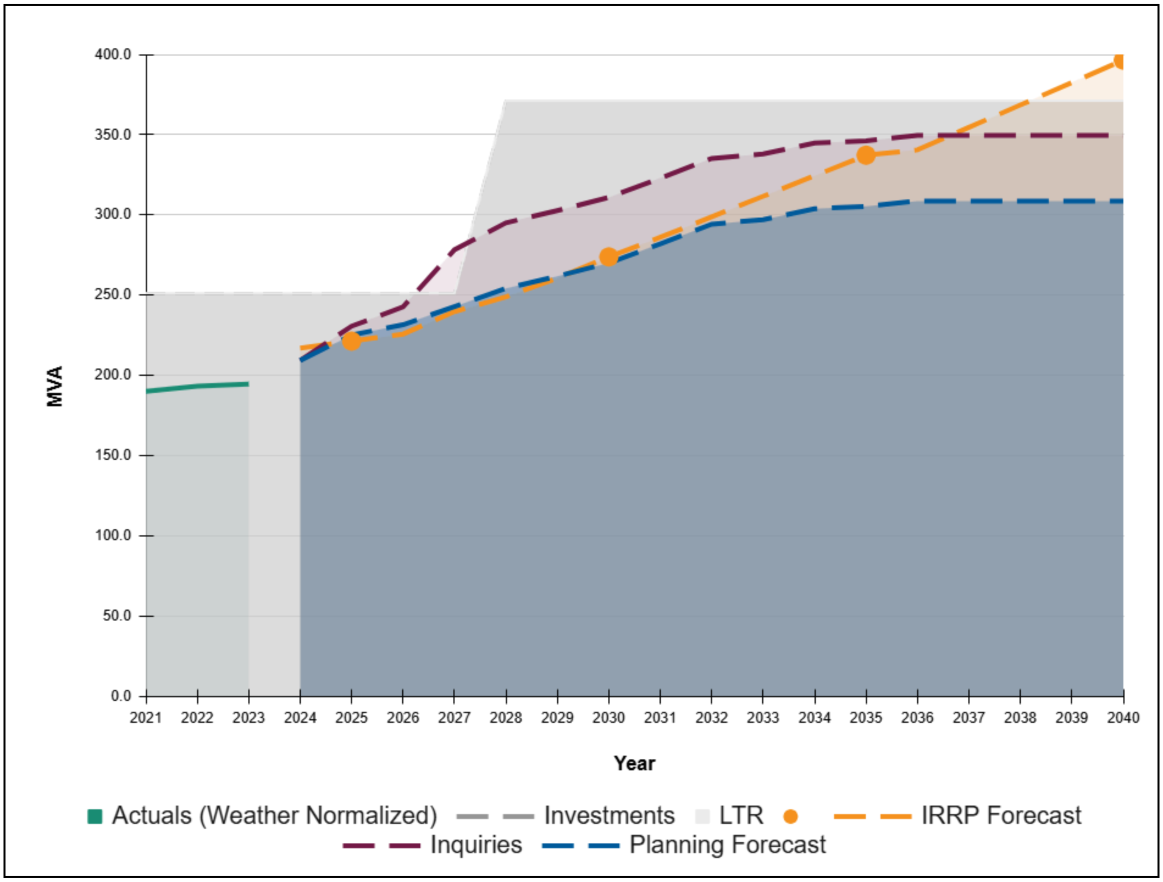
As per the forecasted demand shown in Figure 1, the need for a new station in this region is urgent and the proposed solution will ease capacity constraints and improve reliability of the West 28 kV (North) region upon energization in 2028. However, there still remains a capacity shortfall in the interim period.

Scenario 3: Planning Regions Overloaded by 2030 / Transmission Constrained

This scenario pertains to planning regions where overloads by 2030 are expected based on the IRRP forecast, even after the implementation of proposed wire solutions. It also includes planning regions that are already experiencing transmission system constraints, as identified through Regional Planning. In these cases, NWSs will be essential in managing demand to ensure that the system can operate reliably within limits.

In the medium to long term (2031-2040), load is projected to continue to increase across Kanata, supplied by stations within both the West 28kV (North) and West 28kV planning regions as shown in Figure 2, which is also constrained by transmission limitations[10]. There remains uncertainty in the exact pace of growth given the volume of large load requests contributing to the forecast that are currently at the inquiry stage, as shown through the differences in the Planning Forecast, IRRP Forecast and the Inquires additions. Despite the current uncertainty on the timing, it remains clear that the NWCSP will provide long-term value by helping to defer or delay the need for a *second* new station to serve the region in the mid 2030s.

Figure 2 - 28kV Forecast - Subset of Stations[11]



3.3. NON-WIRES CUSTOMER SOLUTIONS PROGRAM PORTFOLIO

There are six programs to be deployed within the NWCSP portfolio described within Table 3.

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[10] See sections 6.4.1 and 6.4.3 of the IESO's Ottawa Area Integrated Regional Resource Plan, July 31, 2025

[11] The figure includes the following stations: "New" Kanata North (2028 energization), Kanata, Marchwood, Terry Fox, Janet King 28kV and Bridlewood 28kV. Janet King is part of the West 28kV region and supplies a small pocket of customers in the Stittsville area, with interconnections to Bridlewood and Terry Fox, but not Marchwood or Kanata. Therefore Janet King has been excluded for NWCSP deployment at this time.

Table 3 - NWCSP Portfolio

Program	Description
Commercial Retrofit Incentive Adder Program	Customer incentives for a variety of eligible products and technologies that reduce facility peak demand and electricity consumption.
Residential Demand Response Program	Customer incentives to enroll eligible devices in a demand response program. Devices are expected to include smart thermostats, electric vehicles/chargers and battery storage.
Commercial Demand Response (HVAC) Program	Customer incentives targeting commercial HVAC (Heating, Ventilation, and Air Conditioning) loads that enroll in demand response.
Residential Solar and Battery Storage Adder Program	Customer incentives to install both solar and battery energy storage in their homes.
Commercial Solar Adder Program	Customer incentives to install solar generation at their facility.
Commercial Battery Storage Program	Customer incentives for capacity based on the customer's commitment to reduce load through the use of their battery during a demand response event

The programs intend to build on and be delivered in collaboration with the IESO where feasible, given the suite of programs detailed within IESO's 2025-2027 eDSM plan[12], and at this point in time can be reasonably assumed to continue further into the future given the current plan is simply the first 3-year period of an enduring 12 year commitment[13].

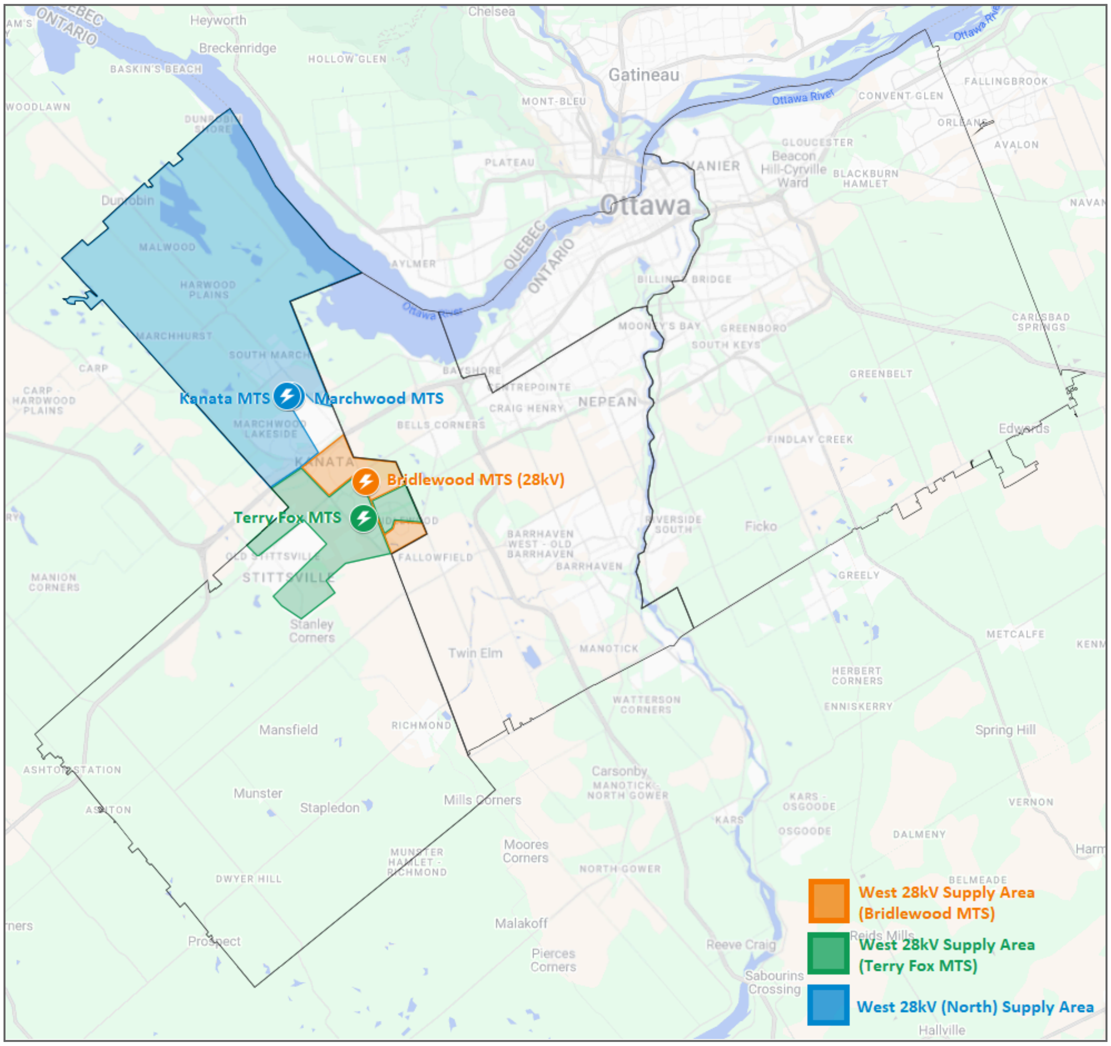
Further details and assumptions for each individual program can be found in section 4.2.2 of this report, as well as Appendix A.

Of note, in addition to interconnections with each other, Marchwood and Kanata stations are also well connected with adjacent stations Bridlewood MTS and Terry Fox MTS located within the West 28kV region. These interconnections support deploying the NWCSP to a broader community for two purposes: Expanding the deployment area will broaden customer accessibility and allow for faster capacity acquisition at the constrained stations. It will also simplify program marketing while helping to minimize customer confusion (eligibility) along the boundaries of the station service areas. Figure 3 depicts the service areas supplied by these stations within Kanata North.

[12]https://www.ieso.ca/-/media/Files/IESO/Document-Library/eDSM/2025-2027-DSM-Plan-with-Beneficial-Electrification.pdf

[13] ttps://www.ieso.ca/Sector-Participants/IESO-News/2025/01/New-12-Year-Energy-Efficiency-Framework

Figure 3 - Kanata Region



The stations serving the Kanata area within the larger NWCSP deployment region serve residential customers as well as class A and B commercial customers. Table 4 below provides additional detail.

Table 4 – Customer Count by Type (2024 Data)

Substation	Residential Accounts	Small Commercial Accounts	Class B Accounts	Class A Accounts
Kanata MTS	6,674	337	78	10
Marchwood MS	8,124	312	78	5
Subtotal	**14,798**	**649**	**156**	**15**
Bridlewood MS	9,446	376	41	0
Terry Fox MTS	15,565	504	63	1
Subtotal	**25,011**	**880**	**104**	**1**
Grand Total	**39,809**	**1,529**	**260**	**16**

4. DISTRIBUTION SERVICE TEST

The DST includes only distribution capacity costs and benefits, per OEB BCA Framework.

4.1. REFERENCE CASE

Hourly historical data from 2023 and 2024 was used to model a reference case[14] for Kanata MTS and Marchwood MTS stations. Historical load patterns were replicated into the future to create 8760 forecasts for each year 2025 to 2050, indexed to changes in load curves resulting from decarbonization-driven electrification of buildings and transportation between 2024 and 2050, derived from the Decarbonization Study's Reference Scenario.

This reference case is the basis used to define both short-term and long-term distribution needs in the region - identifying exceedances beyond planning limits for the purpose of modelling how NWCSP can be used to provide immediate risk mitigation and peak demand support to manage capacity constraints.

For the purposes of this analysis, the combined year-round planning rating for Kanata MTS and Marchwood MTS is 83.9[15] MW (pre-energization of the new Kanta North MTS).

Loading is forecasted to exceed this 83.9 MW planning rating for an increasing number of hours and with greater frequency and magnitude from 2026 through 2028 until Kanata North MTS is commissioned and 30 MW of load can be transferred away from Kanata MTS and Marchwood MTS in 2029.

Hydro Ottawa's planning methodology leverages loading values at each station during the hour of the coincident system peak for forecasting purposes. Coincident system peak refers to the highest point of energy

[14] "Appropriately identifying benefits and costs as incremental to the reference case is essential to ensure that impacts are being treated symmetrically and that none are double counted. This is especially important where the NWS makes use of already-existing solutions." BCA framework page 12.
[15] Marchwood MTS - 33MVA/29.7MW , Kanata MTS 60.2MVA/54.2MW

demand across Hydro Ottawa's full distribution system and the contribution of each substation to that highest system demand at the particular hour. The planning forecast serves as the foundation for evaluating the distribution system's capacity to accommodate future electricity demand. This forecast plays a pivotal role in identifying both the locations and the timing of necessary system upgrades. By considering factors at various levels of granularity - including the station and planning region - the planning forecast allows for a nuanced and targeted approach to system expansion. Its emphasis on location specificity and its incorporation of coincident peak demand requirements - the periods when electricity demand is at its highest - ensure that the distribution system remains robust and capable of meeting the needs of consumers, even during peak load periods.

In contrast, for assessing non-wire solutions as part of this analysis, hourly demand forecast is used. This refers to the electricity consumption recorded for every hour throughout a year that provides a load profile over time. This addresses specific, localized grid constraints to provide a more precise benefit-cost analysis. Hourly data reveals opportunities for load shifting, demand response events, or optimal dispatch of distributed energy resources (DERs) to provide targeted relief to specific parts of the grid at specific times.

4.2. QUANTITATIVE BENEFITS

4.2.1. Distribution Capacity Benefits

The OEB BCA Framework provides a "marginal capacity value" formula[16] (outlined below) for estimating the benefits of NWS for "programmatic investments which are not tied to a single, specific traditional investment" and is referred to as the benefit of the "avoided distribution capacity infrastructure"[17]:

$$Benefit_y = \frac{\Delta PeakLoad_{y,r}}{1 - Loss\%_{y,D\rightarrow r}} \times DistCoincidentFactor_y \times DeratingFactor_y \times MarginalDistCost_y$$

- Where the parameters[18] within the equation are defined as:
  - *Benefit* is the incremental value of NWS capacity
  - Δ*PeakLoad* is the nameplate demand reduction of the NWS
  - *Loss* is the loss percent between the location of the distribution system constraint (D) and the retail delivery or connection point (r) for the NWS.
  - *DistCoincidentFactor* is the input that captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction.
  - *DeratingFactor* is a factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours.

[16] BCA Framework for Addressing Electricity System Needs EB-2023-0125 (oeb.ca). Equation 2.
[17] BCA Framework for Addressing Electricity System Needs EB-2023-0125 (oeb.ca) page 26.
[18] For further context see Table 4 of the BCA Framework, p. 27

- *MarginalDistCost* is the marginal cost ($/kW-yr or $/kVA-yr) of the distribution equipment from which the load is being relieved
- Where:
  - sub-script *y* refers to the given year
  - sub-script *r* refers to the retail delivery or connection point for the NWS, and
  - sub-script $D \rightarrow r$ refers difference in location between the distribution system constraint and the retail delivery or connection point of the NWS

The following outlines the assumptions used by Hydro Ottawa within the equation:

- The analysis uses hourly (8760) feeder-level and customer-level data
- Hydro Ottawa has assumed *Loss* is not material (zero).
- Actual availability of NWS is modelled (during all hours, not assumed nor derated) so "DeratingFactor" and "DistCoincidentFactor" are not required.

Accounting for these assumptions, the equation for modelling NWS benefit analysis therefore is simplified as shown below:

$$Benefit_y = \Delta PeakLoad_y \times MarginalDistCost_y$$

- Where, for the DST
  - Δ*PeakLoad* is the maximum reduction in demand attributable to NWCSP during peak hours.

Annual Marginal Distribution Cost (avoidance benefit) was estimated using an average distribution capacity cost per 100MVA using historical actuals.

The benefit of the portfolio of customer programs was estimated based on the maximum reduction in hourly station load during peak hours. This number is taken to represent the maximum effective kW rating of the combination of programs identified within the portfolio. The maximum output of the NWCSP considered that not all individual programs or measures will be in operation at their maximum capacity at the same time. This number for a year (the maximum impact of the portfolio in a single hour) is applied as ∆PeakLoad within the equation above. The estimated contribution of each program within the portfolio is found within Appendix A on the DST_kW - Updated tab.

For the period of 2026 through 2028, the calculated benefit should be considered as an *avoided capacity benefit*, with the NWCSP acting in place of a traditional infrastructure solution by adding incremental short term capacity within the region. Beginning in 2029, and for the rest of the analysis period, the benefit should be considered a *deferred capacity benefit*, with the incremental capacity helping to delay or defer the need to construct a *second* new station to serve the region in the mid 2030s.

4.3. QUALITATIVE BENEFITS

4.3.1. Reliability

While Hydro Ottawa has not quantified reliability benefits from NWCSP within the BCA, the incremental capacity could enhance the reliability of the distribution system.

The added capacity could be leveraged for support during unexpected events by providing additional flexibility in re-routing power. This is achieved by reducing overall demand on the system and enabling new switching capabilities that allow for faster and more efficient load restoration.

Additionally, energy-saving retrofits, demand response for both homes and businesses significantly reduces electricity demand, especially during peak hours. This lessens the strain on grid infrastructure, reducing the probability of equipment overloads, transformer failures, and voltage issues that can lead to outages, thereby improving overall reliability.

4.3.2. Resilience

Hydro Ottawa has not quantified resiliency benefits associated with this BCA, however, building resilience into Hydro Ottawa's electrical distribution system is vital for withstanding and rapidly recovering from severe weather events like high winds, ice storms, and tornados. NWSs shift the grid from centralized to a more distributed and flexible one. Standalone and hybrid solar PV with BESS, whether at residential, commercial, or utility scale, offer additional resilience. They enable individual homes or commercial facilities to continue operating using stored and self-generated power during distribution outages.

Beyond localized power, strategies like demand response, both residential and commercial, enhance grid resilience by allowing Hydro Ottawa to strategically reduce and shift electricity demand. This pre-emptive or reactive load shedding prevents system overloads when storm-damaged lines reduce capacity, ensuring that available power can be redirected to critical infrastructure. The decentralization of power generation, coupled with the rapid response capabilities of dispatchable BESS and dispatchable demand response, can provide the flexibility needed to support the grid during emergencies. These combined efforts create a system that can rapidly restore power ultimately minimizing the impact of outages on the community.

4.3.3. Innovation and Market Transformation

Given that the regulatory landscape around NWS is evolving in Ontario, there will be lessons learned for both Hydro Ottawa, IESO, the OEB, fellow distribution utilities and other stakeholders across the Ontario electricity sector as a result of pursuit, design, and deployment of the NWCSP in this targeted area of need. The value associated with these lessons learned is difficult to quantify.

4.3.4. Planning Value

Hydro Ottawa expects to continually improve both its planning process, which includes its pre-assessment work to identify the potential for NWS to meet system needs, as well as its approach to leveraging the BCA framework to evaluate individual NWS opportunities. These iterative improvements will reduce risk, increase flexibility, ensure optimized decision making and encourage innovation, all to the benefit of Hydro Ottawa's customers in a way that is difficult to quantify.

4.4. NON-WIRES SOLUTIONS COSTS

All the capacity acquired from NWCSP are situated on customer sites, and would be located behind the meter. This means that the owner and funder of the equipment/device/technology is expected to be the customer.

4.4.1. Participant / Host Costs / Benefits

Given the customer is the ultimate funder, this analysis follows the BCA Framework guidance to exclude host (customer) costs and benefits from the DST and the EST:

> *"… Including host costs would result in an asymmetry that could bias the results of the analysis, as host benefits are explicitly excluded from the EST and DST."*[19]

4.4.2. Non-Wires Solution Acquisition Costs

The BCA framework defines NWS acquisition costs as "contracting costs (to acquire and dispatch NWS), incentive costs, equipment and systems costs (systems, training) to dispatch."

The sum of estimated incentive payments for each of the individual programs comprises the majority of the cost of the portfolio of NWCSP.

The analysis assumes different incentives for the various programs, detailed in Table 5.

[19] BCA Framework section 3.1.4 Symmetrical treatment. Page 12.

Table 5 - Estimated Incentives

Program	$/kW	$/Device
Commercial Retrofit Incentive Adder Program	$ 450	N/A
Residential Demand Response Program	N/A	$ 75
Commercial Demand Response (HVAC) Program	$ 75	N/A
Residential Solar and Battery Storage Adder Program	$ 450	N/A
Commercial Solar Adder Program	$ 450	N/A
Commercial Battery Storage Program	$ 385	N/A

For clarity, Hydro Ottawa is not committing to any specific incentive for any program at this time. The intent of this analysis is to model outcomes based on different inputs to test for sensitivity. References to assumptions about payment type and structure are to be taken as indicative only and for general guidance. Actual incentives are to be determined by Hydro Ottawa during final program design in collaboration with the IESO where appropriate, further adjusted as necessary over time to balance current market conditions and appropriately encourage customer participation while still ensuring the overall program portfolio remains cost effective.

4.4.3. OM&A costs

Hydro Ottawa has currently estimated incremental OM&A costs to deliver this portfolio of programs - including marketing and third party services - of $245,000 per year to operate the portfolio of programs. This estimated value is incorporated into the NPV calculation and included within the DST results.

4.4.4. Ancillary service costs

The BCA framework provides the following examples of ancillary service costs: Voltage regulation, harmonic control, frequency management, and reactive power management. Hydro Ottawa is currently not proposing any of these services and so costs of this variety are not anticipated at this time, and the analysis assumes a zero value in this category.

4.4.5. Program Costs - Summary

Table 6 provides a breakdown of estimated costs for the portfolio. Of note, as the NWCSP will operate as a portfolio, it is expected that Hydro Ottawa will be adjusting its deployment strategy, OM&A and customer incentives associated with each program over the period as necessary, for the purpose of maximizing results in order to address needs in the area.

Table 6 - Non-Wires Customer Solutions Program Costs ($'000s)

	Test Years - Cost ($)					
	2026	2027	2028	2029	2030	Total
Capital	$ -	$ -	$ -	$ -	$ -	$ -
OM&A	$ 245	$ 245	$ 245	$ -	$ -	$ 735
Customer Incentives (Other Revenue)	$ 1,679	$ 1,658	$ 1,985	$ 301	$ 301	$ 5,925
Total Spend	**$ 1,924**	**$ 1,903**	**$ 2,230**	**$ 301**	**$ 301**	**$ 6,660**
NPV of OM&A	**$ 655**					

4.5. DST RESULTS

The Non-Wires Customer Solutions program portfolio modelled would produce a positive Net Present Value of Distribution Service Benefits of $8.01M as outlined in Table 7.

Table 7 - DST Results ($'000s)

Total DST Benefit	$23,076
Total DST Cost	$15,064
NPV Net DST Benefit	**$8,012**
Total MW (2028)	**12.73**

Table 8 summarizes the estimated benefits at the portfolio level, as well as estimated customer incentive costs by individual program.

Table 8 - DST Benefits and Costs ($'000s)

Category	Commercial Retrofit Incentive Adder Program	Residential Demand Response Program	Commercial Demand Response (HVAC) Program	Residential Solar and Battery Storage Adder Program	Commercial Solar Adder Program	Commercial Battery Storage Program
DST Benefits						
Quantitative ($)	$ 23,076					
Explanation	Marginal Avoided Distribution Capacity (Avoided and Deferred Capacity)					
Qualitative	Reliability Resiliency Innovation and Market Transformation Planning Value					
DST Costs						
Customer Incentives	$ 2,700	$ 430	$ 160	$ 1,793	$ 240	$ 602
OM&A	$ 735					
Explanation	-Customer Incentives -Labour and Administration -Marketing	-Customer Incentives -Labour and Administration -Marketing	-Customer Incentives -Labour and Administration -Payments to Aggregators	-Customer Incentives -Labour and Administration -Marketing	-Customer Incentives -Labour and Administration -Marketing	-Customer Incentives -Labour and Administration

4.6. DISTRIBUTION SERVICE TEST RISKS

The following is a list of identified risks associated with the program

4.6.1. Enrollment Risk - Likely

In order to achieve the acquisition of capacity, customer participation is required. While enrollment risk is likely, given the immediate needs in the area any reduction in demand is helpful to addressing system needs. It is important to recognize that as customer incentives represent the bulk of the costs to deliver the NWCSP and customer incentives are generally issued following the acquisition of capacity. Thus, a more conservative achievement in MW capacity will not materially impact the portfolio's cost-effectiveness. Current expectations for participation take into account Hydro Ottawa's history of operating local programs in this area, which includes the Kanata North Retrofit+ Program[20], the Kanata North Smart Thermostat program[21] as well as Hydro Ottawa's history of collaboration with the IESO. As mentioned above, expanding the deployment area to include the additional stations with interconnection capabilities (Bridlewood and Terry Fox) will allow for faster

[20] https://ieso.ca/-/media/Files/IESO/Document-Library/conservation/EMV/2022/PY2022-IF-HOL-Kanata-North-Evaluation-Report.pdf
[21] https://ieso.ca/-/media/Files/IESO/Document-Library/conservation/EMV/2021/PY2021IF-HOL-Smart-T-Evaluation-Report.pdf

capacity acquisition at the constrained stations, and simplify program marketing while helping to minimize customer confusion (eligibility) along the boundaries of the station service areas. Hydro Ottawa's deployment plan will ensure that programs delivering results - which is a combination of speed to market deployment, and customer enrollment (participation) - will be prioritized.

4.6.2. Coordination Risk - Likely

Hydro Ottawa recognizes that coordination with IESO is essential for deployment of the NWCSP. For some of these programs, given a previous history of collaborative program delivery, coordination is expected to be straightforward, while others - namely those which require orchestrated dispatch of flexible resources - are more complex with some uncertainty. Further work will be needed to develop protocols for interoperability for flexible dispatch, data exchange, cybersecurity, and participation agreements.

5. ENERGY SYSTEM TEST

The EST is an optional test for distributors. Hydro Ottawa has elected to quantify the benefits as the NWCSP is being deployed in a region with transmission capacity constraints.

> *"Electricity distributors do not need to complete the EST as part of their BCA, but are encouraged to do so, particularly if they believe the NWS offers significant benefits beyond those of distribution service. However, where an electricity distributor elects to perform the EST, the direction in Table 2 applies, and the electricity distributor is expected to quantify those impacts identified as "quantitative" in that table in line with direction provided in the section above for the DST."*[22]

The approach to the EST follows guidance established in the BCA Framework and should be considered as indicative general guidance only and was not done through consultation with IESO.

5.1. MEETING ENERGY SYSTEM NEEDS—SUMMER/DUAL PEAKING CAPACITY & ENERGY

The IESO defines winter and summer peak hours for the energy system.[23] These peak periods provide a way to assess the average contribution of the portfolio in supporting demand reductions during province-wide system peak hours and are the basis for the IESO's calculation of future capacity and energy costs. Therefore, these IESO-defined peak hours have been used to estimate Energy System Test benefits and costs for the purpose of the BCA.

[22] BCA Framework for Addressing Electricity System Needs EB-2023-0125 (oeb.ca) Page 20.
[23] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Avoided-Costs-2024.xlsx

The IESO cost-effectiveness guide defines "costing periods" generally for summer and dual summer/winter peak periods for the purpose of applying the IESO's calculated values for avoided supply costs specific to these defined periods.

> *"The definition of peak demand has been updated for this [IESO CDM Cost-Effectiveness Guideline] framework to more closely reflect current grid conditions, and the new definition is reflected in the IESO's cost-effectiveness calculations. The details of the peak demand period and the methodology for calculating cost-effectiveness can be found in the IESO Cost-Effectiveness Guide available on the IESO website."*[24]
>
> *Cost-effectiveness in this plan is based on avoided supply costs developed based on the IESO's 2025 Annual Planning Outlook*[25] *and the latest version of the IESO Cost-Effectiveness tool is also available on the website."*[26]

5.2. TRANSMISSION CAPACITY (DEFERRAL OR AVOIDANCE BENEFIT)

Within the EST, it is mandatory to quantify the Transmission Capacity (Deferral or Avoidance Benefit).

> *"Electricity distributors may use (in order of preference) transmission capacity benefits provided by the IESO through the IRRP process, electricity distributor-specific values that have been developed by the electricity distributor, or the estimated transmission capacity values provided in the recent DER potential study developed for the IESO.[*[27]*] Benefits estimated by the IESO IRRP Technical Working Group, if available and of recent vintage, should generally be used in preference to the other values specified."*[28]

As stipulated within the BCA Framework, the analysis has included an estimate of the transmission capacity benefits using the numbers prescribed in the DER Potential Study[29] ($112.26/MW-day)[30] and acknowledges that this "value represents an average of transmission deferral value for the purpose of assessing overall distributed energy resources (DER) potential in Ontario and not for specific projects. The actual deferral value may be quite different …"[31]

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[24] https://www.ieso.ca/-/media/Files/IESO/Document-Library/EMV/IESO-CDM-CE-TestGuide-V9.ashx
[25] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook
[26] https://www.ieso.ca/Sector-Participants/Energy-Efficiency/2025-2036-Electricity-Demand-Side-Management-Framework
[27] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derps/derps-20220930-final-report-volume-2.pdf
[28] BCA Framework for Addressing Electricity System Needs EB-2023-0125 (oeb.ca) page 36.
[29] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derps/derps-20220930-final-report-volume-2.pdf
[30] "If not using values from the IESO IRRP Technical Working Group, electricity distributors are encouraged to select the Business-As-Usual (BAU) values ($112.26/MW-day). Peak demand reductions estimated in order to derive avoided transmission capacity costs should be adjusted to reflect distribution system losses."
[31] February 1, 2023. IESO. Submission to OEB re Benefit-Cost Analysis Framework for Addressing Electricity System Needs (EB-2023-0125).

5.3. AVOIDED COSTS - GENERATION CAPACITY

The Energy System Test within this analysis uses avoided capacity costs the IESO has published within its 2025 Annual Planning Outlook update. Avoided generation costs are estimated based on the capacity values in the 2025 IESO APO and the annual maximum of the operating profile of the combination of NWS from 2026 to 2050.

5.4. AVOIDED COSTS - ENERGY

Avoided energy costs are estimated using the defined winter and summer peak hours identified in the 2025 IESO APO and the hourly operating profile of the combination of NWS running each year from 2026 to 2050.

5.5. NWS ACQUISITION COSTS - INCREMENTAL TO DST COSTS

The IESO costs referenced in the attached appendix on the EST_Costs - Updated tab expressed in $/kW capacity. For the purpose of the present analysis, the incentives are expressed in $/kW-year numbers as costs amortized over the economic lifetime of the underlying asset (see *term* and *discount rate* described in Sections 2.7 and 2.5 respectively above).

5.6. NWS OM&A AND ANCILLARY COSTS - INCREMENTAL TO DST COSTS

No additional OM&A or ancillary costs are contemplated at this time.

5.7. EST RESULTS

The EST evaluates benefits and costs to the broader energy system, including upstream benefits from avoided transmission, generation capacity, and avoided energy consumption during winter and summer.

The NWS portfolio modelled would produce a Net Present Value of Energy System Benefits of $51.9M. Table 9 summarizes EST benefits and costs.

Table 9 - EST Benefits and Costs ($'000s)

Category	Commercial Retrofit Incentive Adder Program	Residential Demand Response Program	Commercial Demand Response (HVAC) Program	Residential Solar and Battery Storage Adder Program	Commercial Solar Adder Program	Commercial Battery Storage Program
EST Benefits						
Quantitative ($)	$ 85,184					
Explanation	Avoided Transmission Capacity Avoided Generation Capacity Avoided Energy					N/A
EST Costs						
Quantitative ($)	$ 20,036	$ 1,591	$ -	$ 8,221	$ 3,122	$ -
Explanation	-Customer Incentives	-Customer Incentives	N/A	-Customer Incentives	-Customer Incentives	N/A

5.8. ENERGY SYSTEM RISKS

IESO-funded programs are assumed to be priced (and structured) to reflect general market risks, risks of non-performance, and contingencies related to energy system benefits. For the purpose of this BCA these risks can be assumed to be zero and there are no incremental risks to be identified.

6. PROPOSED APPROACH TO COST RECOVERY

6.1. NWS VARIANCE ACCOUNT

Given the nascency of the NWCSP program and the operational uncertainties noted above, Hydro Ottawa intends to rely on a symmetrical variance account to record the differences between funding included in base rates for the NWCSP and actual program costs over the rate term, offset by any external funding. The funding for NWCSP will be included in the Non-Wires Solutions Variance Account.

6.2. INCENTIVE MECHANISMS

There are three mechanisms outlined within the Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives[32]: the Shared Savings Mechanism, Performance Target or Scorecard-Based Incentive, and Margin on Payments.

As there are a number of uncertainties around NWCSP, including the collaboration with IESO, that will have an impact on the performance of the portfolio, a performance target or scorecard-based incentive is not

[32] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2023-03/Filing-Guidance-Incentives-for-Third-Party-DERs-as-NWAs-20230328.pdf

appropriate. The approach to using Margin on Payment is in flux, as the proposed DSC amendment related to Margin on Payments has not yet been finalized and may change following comments, including comments from Hydro Ottawa[33] requesting further clarity. Thus, Hydro Ottawa proposes the Shared Savings Mechanism is most appropriate.

Hydro Ottawa proposes a 50%/50% split of the net DST benefits calculated, capped by the DST costs, at the conclusion of the NWCSP activities within the 2026 to 2030 rate filing period. The incentive will be reconciled in the Non-Wires Solutions Variance Account along with the program costs as noted above in section 6.1. Hydro Ottawa's forecast calculation of the Shared Savings Mechanism over the 2026-2030 period is summarized in Table 10 below.

Table 10 - Shared Savings Mechanism Calculation ($'000s)

	2026	2027	2028	2029	2030
Estimated DST Benefits	$ 297	$ 632	$ 783	$ 1,222	$ 1,282
Estimated DST Costs	~~$ 128~~ $ 373	~~$ 251~~ $ 496	~~$ 395~~ $ 640	$ 695	$ 749
Estimated Net DST Benefits	~~**$ 128**~~ **$ (76)**	~~**$ 251**~~ **$ 136**	~~**$ 388**~~ **$ 143**	**$ 527**	**$ 533**
Estimated Net DST Benefits (Capped at value of estimated DST Costs)	~~**$ 128**~~ **$ (76)**	~~**$ 251**~~ **$ 136**	~~**$ 388**~~ **$ 143**	**$527**	**$533**
NPV of estimated Net DST Benefits			~~**$1,486**~~ **$985**		
SSM (50%/50%)			~~**$743**~~ **$492**		

[33] https://www.rds.oeb.ca/CMWebDrawer/Record/901119/File/document

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-5

EVIDENCE REFERENCE:

QUESTION(S):

Table A in IRR 2-Staff-111 includes $20,000 annual Battery Energy Storage System (BESS) OM&A costs from 2028-2030. Please clarify if OM&A costs from the $2.8M annual budget (classified under Non-Wires Programming & System Integration), including Hydro Ottawa staffing and/or third-party contractor costs, are captured in the OM&A cost provided for the four utility-owned (BESS) in Table A of IRR 2-Staff-111.

a. If not all OM&A costs, including Hydro Ottawa staffing and/or third-party contractor costs, have been captured in the $20K annual BESS OM&A, can you clarify the total OM&A cost associated with the four utility-owned BESSs, by individual BESS, across 2026-2030 and annually?

RESPONSE(S):

The $20,000 annual Battery Energy Storage System (BESS) OM&A costs from 2028-2030 are specifically associated with the maintenance activities required to support all proposed Hydro Ottawa-owned BESS installations, as shown in Table A of the response to interrogatory 2-Staff-111. Table A below illustrates the annual expense pertaining to the Hydro Ottawa-owned BESS installations. This funding starts in 2028 upon energization of the first Hydro Ottawa-owned BESS. The $2.8M annual budget for Third Party Non-Wire Alternative Solutions and Non-Wires Customer Solutions Programs (NWSCP) is distinct and separate from the $20,000 annual budget starting in 2028. The $2.8M is intended to support Hydro Ottawa's integration and operation of third party owned non-wires solutions, and includes both internal labour and contracted services. For illustration of this financial separation, please refer to Table A in the response to interrogatory 2-Staff-134 as well as Table A below.

Table A - 2026-2030 NWS and BESS OM&A Breakdown ($'000s)

	Test Years					Explanation
	2026	2027	2028	2029	2030	
Third Party Non Wire Alternative Solutions	$ 2,785	$ 2,601	$ 2,762	$ 2,596	$ 2,539	Alternatively called "Non-Wires Programming & System Integration," New program consisting of services related to integration, operation and monitoring of third party non-wires alternative solutions as well as costs associated with the implementation of the Non-Wires Customer Solutions Programs (NWCSP).
Battery Energy Storage Systems (BESS)	-	-	$ 20	$ 20	$ 20	New program consisting of visual inspection, performance testing and ensuring proper connections/compliance of BESS, alongside their monitoring and management.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-6

EVIDENCE REFERENCE:

QUESTION(S):

Can you clarify the type and dollar value of costs captured in the $13.4M 2026-2030 OM&A budget / $2.8M annual OM&A budget (2026), by different programs (e.g., NWCSP and utility-owned BESS) under “Non-Wires Programming & System Integration”?

For your reference, the following are some references Hydro Ottawa has made across application materials, interrogatory responses and at the Technical Conference regarding this matter:

a. Table A - Non-Wires Programming & System Integration 2026 ($'000 000s) in response to 4-Staff-136 shows that $2.7M of the annual $2.8M budget in 2026 is associated with “Labour”.

b. Page 19 of Schedule 4-1-2 referring to Testing, Inspection & Maintenance OM&A program mentions that the Non-Wires Programming & System Integration will be “leveraging internal and external resources to monitor, control, dispatch, and predict demand” and may employ “software as a service”.

c. On Day 2 of the Technical Conference (p. 94 of Day 2 transcript), L. Heuff confirms that the $2.8M budget contemplates expenditures for the NWCSP and “other expenditures related to management of non-wires solutions such as battery energy storage systems”.

d. Table A – Program Enhancement Costs in 2026 in IRR 4-Staff-134 attributes:

- $2.8M under Testing, Inspection, and Maintenance OM&A Program to “Third Party Non Wire Alternative Solutions” for “Third party operating and maintenance of non-wire alternative solutions” and

- no costs (“N/A”) to “Battery Energy Storage Systems (BESS) in 2026”

RESPONSE(S):

The costs captured in the $13.4M 2026-2030 OM&A budget / $2.8M annual OM&A budget (2026), under “Non-Wires Programming & System Integration” includes both costs associated with services related to monitoring of third party non-wires alternative solutions as well as costs associated with the implementation of the Non-Wires Customer Solutions Programs (NWCSP), which may include software as a service. The costs associated with the maintenance activities related to utility-owned Battery Energy Storage Systems (BESS) are separate, as outlined within Hydro Ottawa’s response to SC-Staff-5.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-7

EVIDENCE REFERENCE:

IRR 2-Staff-67(A)

QUESTION(S):

In the OEB's Filing Guidelines for Incentives for Third-Party DERs, applicants must "provide a detailed benefit-cost calculation for both the third-party owned DER solutions and the wires alternatives to reveal the net savings associated with the DER solutions" when seeking approval of a shared savings mechanism incentive proposal (p.7).

In the submitted BCA, Hydro Ottawa states that "there is no further feasible wire solution capable of addressing this region's needs prior to station energization" (p.9), where the station energization refers to the new Kanata North MTS to be completed in 2028.

Please confirm there is no traditional wires solution that is technically feasible and can be deployed in time to meet the system need in Kanata North from 2026-2028.

RESPONSE(S):

The referenced Filing Guidelines state that: "*Reference scenarios should align with business-as-usual practices. For example, where load growth means that demand on an asset will exceed its capacity, the reference scenario should be the historically standard response of the electricity distributor to addressing such growth*" (as noted in SC-Staff-11).

In its BCA, Hydro Ottawa interpreted the “business-as-usual practices” to mean the construction of an average 100MVA station and associated distribution expansion costs, including estimated relative CCRA contributions.[1]

Hydro Ottawa acknowledges that it should have been more explicit in detailing the rationale behind the decision to use an average distribution capacity cost to illustrate the advancement value of capacity for the 3 year period prior within the BCA submission, and would like to take this opportunity to clarify its rationale in this regard.

The purpose of the average distribution capacity cost is to illustrate the advancement value of capacity for the 3 year period prior to the energization of the new station. This cost represents the traditional wires alternative that would be avoided in the near term and deferred in the long term and was based on the preliminary cost estimates for the construction of an average 100MVA station and associated distribution expansion costs and an estimate of relative CCRA contributions. These annualized station and distribution costs were used in the reference scenario for the purpose of the “business-as-usual” analysis.

In the case of Kanata North another technically viable solution would have been to temporarily bring an incremental 30MVA of capacity to the area from Terry Fox MTS (2 x 28kV circuits at 15MVA each). The temporary capacity would be supplied via two new dedicated feeders extended from Terry Fox MTS to the Marchwood MTS and Kanata MTS supply regions. To make use of these two feeders, additional distribution work would be required within the Kanata North region to redistribute load on existing feeders. The total estimated cost for this wires solution is estimated at $68.5M. This capacity would only support the overload in the Kanata North region up to 2028. Beyond this timeframe, the requirement for the new station persists due to the size of the projected load growth in the region; and the capacity from the two Terry Fox MTS feeders would be required instead within the Terry Fox region.

[1] Please refer to JT1.10 for the details behind the estimates used to develop the average distribution capacity cost cited in the "Program Assumptions" tab of Attachment 2-Staff-67(A) - Appendix A - NWCSP BCA Summary Report.

Hydro Ottawa notes that the advancement value of capacity for the three year period using the average distribution cost has a value of approximately $0.8M/MVA in comparison to $2.3M/MVA of the temporary solution. Had Hydro Ottawa utilized the above solution, the resulting net benefits, and therefore proposed shared savings would have been substantially higher than what is proposed in the application. This temporary solution was ruled out from the reference scenario for the BCA in favour of the “business-as-usual” approach outlined above to mitigate the risk of overstating the benefits of the non-wires solution.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-8

EVIDENCE REFERENCE:

IRR 2-Staff-67(A)

QUESTION(S):

Please confirm there is no other technically and economically viable traditional or non-wires solution (e.g., on-site generation) other than the NWCSP that could meet the system need from 2026-2028 in the Kanata North region.

RESPONSE(S):

With respect to the technical and economic viability of traditional solutions, please refer to the response to SC-Staff-7.

With respect to other non-wires solutions, on-site generation was considered but was scoped out during pre-assessment due to the technical feasibility. This exclusion is predicated on the resource being predominantly solar, which, in the absence of energy storage, is fundamentally non-dispatchable and thus incapable of addressing the system's operational requirements. Storage, in particular, utility owned Battery Energy Storage Solutions (BESS) were considered but also scoped out during pre-assessment due to technical viability. At the time of evaluation, Hydro Ottawa determined it would not be able to effectively deploy a BESS solution in the required timeframe given its lack of experience in deploying and operating BESS solutions of this scale. Hydro Ottawa has now begun these evaluations and is preparing for energization of BESS solutions in other regions in the 2028 to 2030 time frame.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-9

EVIDENCE REFERENCE:

IRR 2-Staff-67(A)

QUESTION(S):

In the submitted BCA, please clarify and explicitly state the traditional wires solution (e.g., feeder extension, new station) that Hydro Ottawa used as the reference scenario to reveal the net savings of the NWCSP in Kanata North. Please also confirm whether it would be feasible to implement this traditional wires solution to meet the system need, should the NWSCP not be an option.

RESPONSE(S):

Please refer to the response to SC-Staff-7 for a detailed explanation of the approach that Hydro Ottawa undertook in the reference scenario, and a discussion of an alternative temporary wires solution for Kanata North that Hydro Ottawa ruled out from the BCA reference scenario in order to mitigate the risk of overstating the benefits of the non-wires solution.

Based on its experience executing similar distribution capacity upgrades in recent years to support customer connections in constrained areas of its grid, Hydro Ottawa believes it would have been feasible to execute the technical solution identified in SC-Staff-7 should the NWCSP not have been an option.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-10

EVIDENCE REFERENCE:

IRR 2-Staff-67(A)

QUESTION(S):

In its quantitative benefits calculation (HOL_IRR_ATT_2-Staff-67(A)), Hydro Ottawa applied an avoidance benefit from 2026-2050. In its submitted BCA, Hydro Ottawa mentions an avoided capacity benefit from 2026-2028, accounting for the new Kanata North MTS energizing in 2028/9, and a deferred capacity benefit to help delay or defer the need to construct a second new station in the mid-2030s (p. 16-17).

Please provide the rationale for the 25-year avoided benefit horizon used in Hydro Ottawa's quantitative benefit calculations.

a. In your rationale, please explain how the NWCSP deployed from 2026-2030 will have benefits persisting through 2050.
b. Please also consider and justify deviations from the IESO's Prescriptive Measures and Assumptions List, which provides values for the effective useful life of electricity demand side management measures.
c. Please also clarify why the same Annual Marginal Distribution Cost avoidance benefit applies after the energization of the new Kanata North MTS in the benefits calculation Provided.

RESPONSE(S):

Hydro Ottawa understands the BCA to be an economic analysis that compares the present value of an NWS investment to the present value of a traditional investment in a transparent way using the Marginal Capacity Value approach outlined within the BCA Framework and the corresponding BCA reporting template. The purpose of the BCA is to determine the economic viability of an NWS investment.

Within Attachment 2-Staff-67(A) - Appendix A - NWCSP BCA Summary Report, both costs and benefits of the reference scenario and NWS portfolio, use common assumptions for discount rate and term to appropriately convert to annualized values ($/kW-year) for proper comparison. As stated in its summary report, Hydro Ottawa's rationale for using a 25 year term was to align with both the IESO's Annual Planning Outlook term as well as Hydro Ottawa's Decarbonization Study term. In addition, the 25 year term aligns with the guidance at page 13 of the BCA Framework: "*The "long-term net benefit" of distribution service for customers in this case refers to the economic value realized by customers over a time horizon comparable with that used to value traditional poles and wires capital assets.*

a. The 25-year analytical term in the Benefit-Cost Analysis (BCA) is employed as a standardized economic denominator to calculate the annualized cost and benefits of the Non-Wires Solution (NWS) versus the traditional wires solution. This term ensures an appropriate, equivalent comparison framework for expenditures made during the 2026–2030 filing period. It is essential for determining the Present Value of net Distribution Service Benefits on a common basis, and does not constitute a claim or projection of benefits or costs beyond this rate period.

b. The IESO's Prescriptive Measures and Assumptions List (MAL), and specifically the Effective Useful Life (EUL) values it contains, are directly relevant for the detailed program design phase. These values will be considered following regulatory support of the NWCSP to inform measure selection, establish realistic operational longevity (in collaboration with the IESO, where feasible), and ultimately determine the final incentive values provided by Hydro Ottawa to participating customers.

Conversely, the EUL values are not directly relevant to the Benefit-Cost Analysis (BCA) phase because the BCA uses a standardized 25-year analytical term for all projects. As noted in part (a), this term is required to ensure an equivalent economic comparison of the Non-Wires Solution to a traditional wires investment.

c. Based on the guidance in the BCA Framework at page 26, Hydro Ottawa understands the approach and formula to calculate the Marginal Capacity Value to be the same whether it is calculating an avoidance benefit or a deferral benefit. That is because: "*This approach is useful for more programmatic investments which are not tied to a single, specific traditional investment. This approach is similar to calculating marginal distribution capacity value for other types of programs*. Using the Marginal Capacity Value approach, Hydro Ottawa detailed its logic for why the same benefit is applied after the energization of the new station occurs beginning on page 16 of Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report: *For the period of 2026 through 2028, the calculated benefit should be considered as an avoided capacity benefit, with the NWCSP acting in place of a traditional infrastructure solution by adding incremental short term capacity within the region. Beginning in 2029, and for the rest of the analysis period, the benefit should be considered a deferred capacity benefit, with the incremental capacity helping to delay or defer the need to construct a second new station to serve the region in the mid 2030s.*

Figure 2 within Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report illustrates the potential need for a second station within the region around 2037 (IRRP Forecast) in absence of any capacity benefits resulting from the NWCSP.

SETTLEMENT RESPONSES TO ONTARIO ENERGY BOARD STAFF

SC-Staff-11

EVIDENCE REFERENCE:

QUESTION(S):

The BCA Framework requires that benefits and costs be quantified as incremental to a clearly defined reference scenario, which represents the business-as-usual outcome:

"Reference scenarios should align with business-as-usual practices. For example, where load growth means that demand on an asset will exceed its capacity, the reference scenario should be the historically standard response of the electricity distributor to addressing such growth." (p.12)

Please ensure that the OM&A cost inputs in the quantitative BCA calculations reflect those costs that are incremental to the reference scenario. Specifically, include all OM&A costs (e.g., existing and new staff time) that would be incurred under the proposed NWCSP in Kanata North but would not have been incurred by the traditional wires-based approach that constitutes the reference scenario.

RESPONSE(S):

Please see the response to Updated SC-Staff-4.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-1

EVIDENCE REFERENCE:

JT1.14, VECC 5.1(A) – Excel
Attachment 3-1-1(C), 2. Load Forecast Data – kWh
Attachment 3.0-VECC-13(A) – Historical_Forecast_Values

QUESTION(S):

a) It is noted that, in the Residential model, the historic (2013-2023) values used for the variable "CustsEconVar" have change in JT1.14 VECC 5.1(A) from those used in the original model (Attachment 3-1-1(C), 2. Load Forecast Data – kWh). Please explain why.
b) Please provide a revised version of Attachment 3.0-VECC-13(A) – Historical_Forecast_Values consistent with JT1.14, VECC 5.1(A).
c) Please provide the source of the updated population and economic forecast used in JT1.14, VECC 5.1(A).

RESPONSE(S):

a) The original forecast, filed as part of Schedule 3-1-1 - Revenue Load and Customer Forecast, used an economic forecast from the Conference Board as of September 2024. The updated forecast for interrogatory response 3-SEC-62 used an updated Conference Board forecast (as of July 2025). The CustEconVar is a composite variable using population and GDP, with an 80% weight on population and 20% on GDP. The historical values for the CustEconVar variable changed as the Conference Board revised its historical GDP values as of July 2025.

b) Please see Attachment SC-VECC-1(A) - Historical and Forecast Values for Population GDP and the Blended Economic Variable July 2025 Update.

c) See response to a).

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-2

EVIDENCE REFERENCE:

JT1.14, VECC 5.5, Table C
Attachment JT1.14-VECC-5.0(A) - SEC-62 - Load Forecast Data – Customers

QUESTION(S):

a) With respect to the GS 1,000-<1500 class, it is noted the customer counts are the same in both references for the years 2025 to 2027 (averaging 89, 90 and 91 respectively). However, they differ for the years 2028-2030. Please explain the reason for the differences in the latter years.

RESPONSE(S):

a) Tab 'GS1500_Custs Err' in Attachment JT1.14-VECC-5.0(A) - SEC-62 - Load Forecast Data – Customers is the output from the regression model used to forecast customers. Table C from undertaking response JT1.14, VECC 5.0 is the output from the regression model, along with an adjustment for one customer moving to large usage in 2027 and another in 2028 due to commercial electrification.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-3

EVIDENCE REFERENCE:

Attachment 3-SEC-62(A) - Bill Determinants Actuals for Nov 2024-June 2025, Customer Tab
JT1.14, VECC 5.5, Table C
Exhibit 3, Tab 1, Schedule 1, Table

QUESTION(S):

a) With respect to the GS 50-<1,000 class. Please explain why the forecast customer counts for 2026-2030 are lower in JT1.14, VECC 5.5, Table C (i.e., 2,952 per the updated forecast in SEC 62) than in the initial Application (3,053 per Exhibit 3, Tab 1, Schedule 1, Table 3) when the actual value for June 2025 (as used in SEC 62) of 3,076 is greater than the initial 2025 forecast value of 3,053.

RESPONSE(S):

a) The JT1.14-VECC-5.0 Table C values incorrectly removed the November 2024 rate reclass customers twice. Since the 3.0-SEC-62 forecast included historical data through to June 2025, any impact from the November 2024 rate reclassification is reflected within that historical data. Consequently, no additional adjustment should have been applied for this reclassification. The General Service 50-1000 kW count should be 3,076. Table C has been corrected below.

Revised Table C - 3.0-SEC-62 Revenue Load Forecast Monthly Average Customer and Connection Count by Class

	2025	2026	2027	2028	2029	2030
Residential	344,451	346,478	348,504	352,008	356,364	360,320
General Service < 50 kW	25,821	25,969	26,039	26,162	26,314	26,452
General Service 50-1000 kW	3,072	3,076	3,076	3,076	3,076	3,076
General Service 1000-1500 kW	89	90	91	90	90	91
General Service 1500-5000 kW	79	80	79	79	79	79
Large User	10	11	12	13	14	14
Unmetered Scattered Load Connections	4,140	4,243	4,358	4,472	4,587	4,702
Sentinel Lighting Connections	48	47	46	45	44	43
Street Lighting Connections	64,822	65,686	66,596	67,505	68,415	69,324
TOTAL	**442,475**	**445,556**	**448,677**	**453,326**	**458,859**	**463,977**

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-4

EVIDENCE REFERENCE:

Attachment 3-SEC-62(A) - Bill Determinants Actuals for Nov 2024-June 2025, Customer Tab
Attachment 3.0-VECC-16(A) - 2013-2025 Monthly CustomerCounts
Attachment 3.0-VECC-15(A) - GS and LU Customer CountForecasts_adjustments
JT1.14, VECC 6.3

QUESTION(S):

a) With respect to the LU class, please explain the increase in customer count between October 2024 (10) and November 2024 (11) per Attachment 3.0-VECC-16(A) - 2013-2025 Monthly Customer Counts.
b) With respect to the LU class, do the actual January 2025 customer counts (per SEC 62(A) and VECC 16(A)) include both: i) the GS reclassifications set out in VECC 15(A) and ii) the reclassification of the LU customer due to disaggregation per JT1.14, VECC 6.3?

RESPONSE(S):

a) The increase is due to customer reclassification. Please refer to interrogatory response 3-SEC-63, part (b), Table A for details on customer reclassification.

b) Yes, the January 2025 customer counts per 3-SEC-62(A) include both GS reclassifications and the reclassification of the LU customer due to disaggregation.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-5

EVIDENCE REFERENCE:

VECC 29 and 72
JT1.14, VECC Staff 127 (revised October 4, 2025)
VECC 72
Attachment 3.0-VECC-15(A) - GS and LU Customer Count Forecasts_adjustments
JT1.14, VECC 6.1
Exhibit 3-1-1(B), page 15
Attachment 3-SEC-62(A) - Bill Determinants Actuals for Nov 2024-June 2025, Customer Tab
Attachment 3-VECC-16(A) - 2013-2025 Monthly Customer Counts

QUESTION(S):

a) With respect to the GS<50 class, JT1.14, VECC 6.1 states:

"Elected to not remove the one GS 50 rate class customer due to electrification; however, its kWh and kW impact was reflected in the revenue load forecast."

While VECC 29 does not show any adjustments to GS<50 kWh due to Large Load electrification, both VECC 15(A) and Staff 127 (revised) show a reduction in customer count of one in 2029 and 2030 due to Large Load electrification. Please reconcile.

b) With respect to the GS 50-999 class:
- Exhibit 3-1-1(B), page 15 states that the customer count was held constant at the October 2024 level.
- VECC 15(A) indicates that the initial forecast value was 2944.
- JT1.14, VECC 6.1 states: "The GS 50-999 rate class count was held constant with the January 2025 forecast count to avoid further decreases based on historical trending."

- Adjusting for reclassification (+109 per VECC 15(A) yields 3,053 - consistent with the forecast values per Exhibit 3-1-1, Table 3

However, both VECC 16(A) and SEC 62(A) report that the actual count as of October 2024 was 2,952 (not 2,944), please reconcile.

c) With respect to the GS 1500-4999 class:

- JT1.14, VECC 6.1 states: "An additional GS 1500-4999 kW was removed starting in 2026 as this customer was reclassified at the end of 2024."
- VECC 29, Table B and VECC 72 attribute reductions to the kWh and kW forecast due to Large Load electrification starting in 2026.
- VECC 15(A) does not show any reductions in customer count due to Large Load electrification. However, Staff 127 (revised) shows a reduction of one customer starting in 2024.

Given the foregoing, please clarify the following:

i. Are the kWh and kW reductions shown in VECC 29 and VECC 72 that start in 2026 due to the 2024 customer reclassification (per JT1.14, VECC 6.1) or due to an expected Large Load electrification in 2026? If due to customer reclassification, is it appropriate to include in VECC 29, Table B and VECC 72? If due to Large Load Electrification, why doesn't Staff 127 (revised) show a further customer count reduction of 1.0 in 2026 and after?

ii. Please explain what the reduction of 1 customer starting in 2024 (per Staff 127 revised) represents. As part of the explanation, please indicate: i) whether it is associated with the customer that was reclassified at the end of 2024 (per JT1.14, 6.1) and ii) why it is attributed to requests from customer for future Large Load electrification increases.

RESPONSE(S):

a) The historical consumption data related to the GS<50 customer (that is forecasted to be a large user) was not removed from the GS<50 customer class when generating the load forecast for the GS<50 class though this customer was added to the large use count. Consequently, Table B of interrogatory 3.0-VECC-29 does not reflect any reduction of kWh consumption within the

GS<50 category. However, the incremental kWh and kW large load impact for this customer is included in the Large User electrification total in Table B.

b) At the time data was provided to iTron to develop Hydro Ottawa's revenue load forecast, the General Service 50–1,000 kW class had 2,944 accounts for October 2024. Subsequently, while finalizing the official year-end reporting for the Reporting and Record Keeping Requirements (RRR) in the first quarter of 2025, an adjustment was made to correct an error where several accounts had been mistakenly left out of the October 2024 monthly figure. As a result of this correction, the final official customer count for that class for October 2024 was updated to 2,952 accounts.

c) i) The kWh and kW reductions shown in 3.0-VECC-29 and 9.0-VECC-72 that began in 2026 are due to expected Large Load electrification. A customer in the original revenue load forecast reclassified earlier than anticipated at the end of 2024. In response to this question, Hydro Ottawa proposes to update the revenue load forecast to remove the customer who reclassified earlier than expected from the Large Load electrification forecast as their billing determinants were moved as part of the 2024 reclassification adjustments; no other changes are proposed.

ii) Please see response to part (c) i) above.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-6

EVIDENCE REFERENCE:

JT1.14, VECC 14.1
JT1.14, VECC 13.1.1
JT1.14, VECC 15.1

QUESTION(S):

a) The response to JT1.14, VECC 14.1 indicates that annual CDM values from Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast, Table 3-2 have not been adjusted to account for the fact that CDM savings are not realized starting in January; rather, savings accumulate throughout the year with full realization often lagging until the subsequent year.

Similarly, the response to JT1.14, VECC 15.1 indicates that the values in Table 3-2 have not been adjusted to account for the fact that CDM savings are not realized starting in January; rather, savings accumulate throughout the year.

However the response to JT1.14, VECC 13.1.1 indicates that the CDM values in Exhibit 3, Attachment 3-1-1(B) Table 3-2 were adjusted to reflect a ramp-up period for new programs.

Please reconcile and provide revised Undertaking responses as required.

RESPONSE(S):

a) The figures in Table 3-2 from Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast do not reflect the ramp-up adjustment. The figures are the cumulative annual CDM amounts provided to Itron prior to the adjustment. Therefore the response to JT1.14-VECC-13.0 has been updated and is attached to this response as Attachment SC-VECC-6(A) - Revised JT1.14-VECC-13.0. In addition, the attachment JT1.14-VECC–13(D) -EnergySaving Reconciliation has also been updated and provided as Attachment SC-VECC-6(B) - EnergySaving Reconciliation (Revised).[1]

[1] Previously provided as Attachment JT1.14-VECC–13(D) - EnergySaving Reconciliation

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-7

EVIDENCE REFERENCE:

JT1.14, VECC13.3 and 13.4
Attachment 1-Staff-11A – CDM Supporting Data

QUESTION(S):

a) The response to JT1.14, VECC 13.4 indicates that corrections have been made to Attachment 1-Staff-11A – CDM Supporting Data. Please provide a revised (corrected) version of the file.

b) With respect to JT1.14, VECC 13.4, Table A, please explain the basis for the values included in columns B and D and explain why these values were not included respectively in Exhibit 3, Attachment 3-1-1(B), Table 3-2 and HOL_IRR_ATT_1.Staff 11 (A) – CDM Supporting Data (CDM Summary Tab).

c) The response to JT1.14, VECC 13.3 suggests that the accompanying Table A and Attachment JT1.14-VECC-13.0(D) – Energy Saving Reconciliation explain the differences between: i) Exhibit 3, Attachment 3-1-1(B), Table 3-2 and ii) HOL_IRR_ATT_1.Staff 11 (A) – CDM Supporting Data (CDM Summary Tab). Table A appears to reconcile the two references but, contrary to the response to JT1.14, VECC 13.1.1, does not include the ½ adjustment (reflecting a ramp-up period for new programs) as part of the variance explanation. Please reconcile.

d) If Exhibit 3, Attachment 3-1-1(B), Table 3-2 does not represent the cumulative CDM and eDSM savings used in the Revenue Load Forecast, please provide a schedule that does and indicate how it was derived from the corrected version of Attachment 1-Staff-11A – CDM Supporting Data requested in part (a).

RESPONSE(S):

a) Attachment JT1.14-VECC-13.0(A) - CDM Supporting Data is a revision of Attachment 1-Staff-11(A) – CDM Supporting Data.

b) Please note Hydro Ottawa believes the reference should be JT1.14, VECC 13.3. The values presented in JT1.14, VECC 13.3, have been revised; please refer to PDF Attachment SC-VECC-6(A) - Revised JT1.14-VECC-13.0 and Excel Attachment SC-VECC-6(B) - EnergySaving Reconciliation (Revised).

c) Table 3-2 are the cumulative annual CDM targets. ~~Please refer to Excel Attachment SC-VECC-7(A) - Total eDSM calculation that summarizes the individual rate class files from SC-VECC-8. Please note, upon reviewing the summary file we noted the years 2011 to 2022 do not balance as we are missing a file for the General Service 50 to 1,000 kW Non-interval class that existed during that period. We will update this response when we obtain the additional file.~~ While reviewing the summary file it was realized that Table 3-2 had a data entry error for GS1000 and GS1500. An update Table 3-2 from Attachment 3-1-1(B) - Hydro OttawaLong-Term Electric Energy and Demand Forecast has been provided in Updated Excel Attachment SC-VECC-7(A) - UPDATED Total eDSM Calculation- Updated Nov 6, 2025, and below in Table A. The error only existed in preparing the noted table; there was no related error in the revenue load forecast.

1 **Table A - Updated Table 3-2 from**

Cumulative CDM Saving (MWh)						
Year	**Residential**	**GS50**	**GS1000**	**GS1500**	**GS5000**	**Large User**
2013	20,616	7,385	78,260	10,367	-	-
2014	34,044	16,012	113,534	15,371	-	-
2015	53,784	25,619	146,549	20,279	8,821	6,370
2016	88,655	34,888	177,653	25,127	13,768	12,057
2017	159,552	45,541	206,701	29,884	19,349	34,317
2018	176,325	55,895	226,301	33,446	23,262	35,028
2019	180,374	66,202	245,812	37,141	27,357	35,899
2020	183,289	71,052	257,109	39,717	32,093	36,753
2021	184,870	77,983	271,675	42,909	40,709	38,644
2022	186,089	81,736	278,304	44,946	45,544	39,332
2023	187,479	86,424	286,089	47,248	51,086	53,831
2024	189,751	92,367	298,096	49,230	53,484	56,869
2025	211,380	98,980	328,177	54,198	60,368	61,696
2026	233,653	105,223	353,605	58,398	66,272	66,481
2027	256,621	111,716	379,729	62,712	72,327	71,417
2028	280,337	118,534	406,704	67,167	78,565	76,544
2029	304,847	125,727	434,635	71,780	85,006	81,887
2030	327,687	133,351	463,638	76,570	91,674	87,476

2

3 d) As noted in the response to JT1.14-VECC-14.0, Table 3-2 presents the annual CDM values.
4 iTron uses these values and applies several adjustments to transform them into monthly
5 variables used in the load forecasting model. Refer to Excel Attachments SC–VECC-8(A)
6 through (F) for detailed calculation of the CDM/eDSM monthly variable.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-8

EVIDENCE REFERENCE:

JT1.14, VECC 15.1
Attachment JT1.14-VECC-15.0(A) - eDSM Savings Reconciliation

QUESTION(S):

a) It is noted that Attachment JT1.14-VECC-15.0(A) simply calculates the differences between the two tables referenced in the undertaking and attributes it to the half year savings factor. However, the undertaking requested "schedules for each class that demonstrates how the values in Table 13 were derived from those in Table 3-2".

As initially requested, please provide a schedule for each rate class setting out the derivation of the annual values in Exhibit 3-1-1, Table 13 and how they are consistent with the values set out in Table 3-2.

RESPONSE(S):

a) The derivation of annual values in Exhibit 3-1-1, Table 13 is provided in response to 3-Staff-124. Please refer to Attachment 3-Staff-124(A) - Annual eDSM kWh savings.

Please refer to Excel Attachments SC-VECC-8(A) through (F), which show how the first year factor was computed as well as how the values set in Table 3-2 reconcile to Schedule 3-1-1 - Revenue Load and Customer Forecast, Table 13. Please note, upon reviewing the summary file attached to SC-VECC-7 we noted the years 2011 to 2022 do not balance as we are missing a file for the General Service 50 to 1,000 kW Non-interval class that existed during that period. We will update this response when we obtain the additional file.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-9

EVIDENCE REFERENCE:

Attachment JT1.14-VECC-13.0(D) – Energy Saving Reconciliation, CDM 2026 to 2030 Tab
JT1.14-VECC-16.0(A) - Energy Savings Forecast 2025-2036

QUESTION(S):

a) With respect to Attachment JT1.14-VECC-13.0(D), were HOL's 2024 annual savings (per the CDM 2026-2030 Tab) derived using the IESO's targeted 2024 provincial savings per the 2021-2024 Conservation and Demand Management Program, December 15, 2022.
   - If yes, please provide a schedule setting the derivation of HOL's 2024 savings by Program area and the basis for HOL's share of each Program area's savings.
   - If not, please provide a schedule setting the derivation of HOL's 2024 savings by Program area and indicate the sources for the various inputs.

b) JT1.14, VECC 16.3 asked for the sources of the inputs used to calculate HOL's 2025-2030 annual savings. Please provide the source(s) for the provincial level savings used in JT1.14-VECC-16.0(A) - Energy Savings Forecast 2025-2036 (i.e., cells A3->M19).

c) For the years 2025-2030, the HOL's annual savings as set out in Attachment JT1.14-VECC-13.0(D) – Energy Saving Reconciliation, CDM 2026 to 2030 Tab do not match those set out in JT1.14-VECC-16.0(A) - Energy Savings Forecast 2025-2036. For example, for 2030 the total annual savings shown in VECC-13(D) are 75,441 MWh where as in VECC 16.0(A) they are 79,027 MWh (sum of X27->AD27). Please explain why and update the evidence as required.

RESPONSE(S):

a) The 2024 demand savings were based on the 2025's forecast minus 2%. Please see Excel Attachment SC-VECC-9(A) - Energy Savings Forecast 2025-2036 for more details.

b) Provincial savings for 2025-2029 were based on the 12 year eDSM framework total demand savings target of 3,000 MW[1] that was announced by the Minister of Energy and Electrification. Hydro Ottawa estimated 2025's program level savings based on actual reported program savings for 2021-2023. Then Hydro Ottawa incorporated yearly growth 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.

c) The original figures in column C of Table A of JT1.14-VECC-13.0 and related attachment JT1.14-VECC-13.0(D) - EnergySaving Reconciliation mistakenly included as first year values the persistence of savings from prior years' conservation programs for years 2024-2030. Refer to Excel Attachment SC-VECC-6(B) - EnergySaving Reconciliation (Revised) for updated values. The annual savings for 2024-2030 now reconcile except for 2030 where the revenue load forecast (column A of Table A) did not include estimated savings of 2,509 MWh from the Energy Affordability Program.

[1] Ontario Ministry of Energy "Ontario Launches New Energy Efficiency Programs to Save You Money" (January 7, 2025).

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-10

EVIDENCE REFERENCE:

Exhibit 7-1-1, page 10
7-VECC 53
Technical Conference, Day 3, page 46

QUESTION(S):

a) What portion of the $1.3 M is associated with the Energy Transition, Customer Strategy and Innovation Group's role in the development and implementation of Hydro Ottawa's NWSs strategy and carrying out efficiency savings programs?

b) How much of this portion of the $1.3 M is allocated to each of the customer classes for 2026?

RESPONSE(S):

a) Two business units comprise the Energy Transition, Customer Strategy and Innovation Group, both of which are major-customer-facing and could be involved in the discussion of NWSs. One of these teams, however, accounts for ~40% ($0.5M) of the total attributable cost, and will be responsible for leading the development and deployment of the Non-Wires Customer Solutions Program (NWCSP). While most of this team's time is directed to the development and deployment of the NWSCP strategy and supporting customers interested in local energy efficiency initiatives, they are also involved in other non-NWSCP activities.

b) As described in the above references, costs for the group are allocated to customer classes on the basis of a one year sample of customer contacts. The nature or context of those contacts was not a factor in the analysis. Bearing this caveat (and the one described in part a above) into consideration, Table A details the allocation of the $0.5M to customer classes as presented on Tab I9 of the 2026 Cost Allocation Model submitted as Attachment 1-Staff-1(H) - 2026 Cost Allocation Model.

Table A - 2026 Allocation of USofA 5510 Costs to Customer Classes ($'000s)

	Residential	GS < 50kW	GS 50-1,499 kW	GS 1,500-4,999 kW	Large Use	USL	Total
Cost	$ 13	$ 40	$ 242	$ 111	$ 128	$ 1	$ 534
%	2.35%	7.56%	45.27%	20.78%	23.95%	0.10%	100.00%

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-11

EVIDENCE REFERENCE:

JT3.8

QUESTION(S):

a) Does the 2026 cost of $8 also include the costs of continuing to bill commercial Net Metering customers manually (Exhibit 6-4-3, page 4)? If not, please update the cost to include this expense.

RESPONSE(S):

The estimated $8 per month, per account, cost for 2026 includes the expenses for manually billing commercial net-metering customers.

Hydro Ottawa notes it is not proposing to charge net-metering customers $8 per month, the costing was updated to provide a comparison of illustrative revenues in response to undertaking JT3.8.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-11b

EVIDENCE REFERENCE:

CCC-66, Table A
Exhibit 8-3-2, page 3
Technical Conference, Day 3, pages 54-55

QUESTION(S):

a) Do the costs set out in CCC-66, Table A represent the costs for the respective bullet points set out in Exhibit 8-3-2, page 3? If not, please identify the 2026 costs associated with each of the five bullet points.

b) Please provide further explanation as to the activities associated with the second bullet point on page 3 of Exhibit 8-3-2 (i.e., Incremental internal labour for wholesale market settlement activities).

RESPONSE(S):

a) Yes, the costs set out in interrogatory response 8-CCC-66 Table A represent the costs for each bullet point described in Schedule 8-3-2 - Standard Supply Service Charge, page 3.

b) Examples of activities associated with wholesale market settlement activities include:
   - Provide monthly reports for market settlement;
   - Calculate monthly revenue accrual;
   - Create journal entries to record monthly wholesale market revenue ;
   - Reporting on aged arrears and completing bad debt write-offs;
   - Perform monthly reconciliation between the billing system and the ERP;
   - Monitor wholesale financial transactions in the general ledger ;

- Generate internal reports for RPP and SSS data (consumption, count) and monthly commodity rate changes;
- Perform general ledger validations for RPP rate changes; and
- Manage and execute financial account configuration/mapping within the billing system.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-12

EVIDENCE REFERENCE:

ED-32 b)

QUESTION(S):

a) ED 32 b) indicates that Hydro Ottawa currently has 6 customers with generation over 500 kW who do not contract for Standby service and are not subject to standby rates. Does Hydro Ottawa meter the generation for each of these customers so as to determine when it is ON and when it is OFF?

   i. If not, why not?

b) If yes, have any operated such that they would be subject to Backup Overrun charges in the past three years and, if yes:

   i. how many customers and how many times?
   ii. Has HOL imposed Backup Overrun charges in each instance?

RESPONSE(S):

a) Yes, the generation is metered for these customers to allow Hydro Ottawa to monitor if they are using Hydro Ottawa as a standby service.

b) Hydro Ottawa has not imposed Backup Overrun charges to any of these customers. These customers operate their generation at minimal intervals throughout the month (i.e. for global adjustment peak shaving) and are not subject to the backup overrun charge.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-13

EVIDENCE REFERENCE:

ED-31 b)

QUESTION(S):

a) With respect to Table B, please clarity how an “instance” is defined – i.e., is it: i) a month where the generator was off at the time of the distribution system peak (3 pm-6pm) such that for each customer there would be a maximum of 12 instances or ii) an the number of hours where the generator was off at the time of the distribution system peak (3 pm-6pm) such that for each customer there would be a maximum of 36 instances or iii) some other metric?

RESPONSE(S):

a) An “instance” is defined as an hour where the generator was off (i.e., reading 0). Due to system peak date and hour varying each month, a high level approach was taken for the analysis in interrogatory response ED-31. This involved assuming each hour between 3pm and 6pm daily was “at the time of distribution peak”. In 2024, this results in a total of 1,464 instances (4 hours x 366 days).

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-14

EVIDENCE REFERENCE:

JT1.14, VECC 21

QUESTION(S):

a) JT1.14, VECC 21 states:

“For clarification, Section 4.2 of Schedule 7-1-3 - Standby Service Charge should have been written as “In this example the customer has elected for 0 kW Contracted Demand. Billed Backup Overrun Demand would be 250 kW; Contract Demand of 0 kW – (Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW).””

Should the formula actually be expressed as:
“(Metered Peak generator OFF – Metered Peak generator ON) – Contract Demand”?

RESPONSE(S):

In general, standby service charge is based on Contract Demand of 0 kW – (Metered Peak generator OFF of 450 kW – Metered Peak generator ON of 200 kW). If the result is <0, Backup Overrun charge applies.

Backup Overrun demand is calculated as the absolute value of (Contract Demand – (Metered Peak generator OFF – Metered Peak generator ON)).

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-15

EVIDENCE REFERENCE:

Staff 191
Technical Conference, Day 1, pages 87-88

QUESTION(S):

a) Staff 191 states: "When any new customer, including a large-use customer, requests a connection, they must provide a load estimate. This estimate is used in the distribution system's design, and the necessary capacity is reserved to meet that specific load."

In instances where the customer is installing behind the meter generation, is the customer's load estimate used in system design and to determine the required system capacity the same as if the customer had no behind the meter generation) or is the load estimate adjusted?

i. If the load estimate is adjusted, please explain how and whether the customer contracting for standby power would affect the nature of the adjustment.

RESPONSE(S):

a) As described in the response to interrogatory 7-VECC-61 part (b), the design of a customer system with embedded generation is configured differently to accommodate bi-directional power flow and ensure system stability.

Hydro Ottawa's system design for capacity availability solely depends on the customer's load estimates. It is the customer's responsibility to decide whether or not to factor behind the meter generation into their load estimates. There are two scenarios based on how the customer presents their load estimate to Hydro Ottawa:

- Customer does not consider behind the meter generation (Requests Gross Capacity):
  - The system design makes the gross capacity available.
  - The customer would then be subject to the economic evaluation true-up process to pay for any unutilized expansion.
- Customer considers behind the meter generation (Requests Net Capacity):
  - The system design makes the net capacity available.
  - The customer would be subject to additional standby charges if extra capacity needs to be reserved for instances when generation is unavailable.

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-16

EVIDENCE REFERENCE:
3.0-VECC-15

QUESTION(S): Update response to interrogatory 3.0-VECC-15 if customer count has changed. Update Tables from Exhibit 3 if required. Updated necessary interrogatories 3.0-VECC-21 to 3.0-VECC-27 if volumes changed.

RESPONSE(S):

Please find a summary of the changes to the proposed revenue load forecast, including:

I. A duplication error stemming from customer reclassification required a correction to the figures for consumption, demand and customer count (referenced in undertaking JT3.21, JT1.14-VECC-6.0, pre-settlement SC-VECC-3 as well as undertaking JT1.14-VECC-5.0-October 8)
II. Incorporating the final 2024 historical count (up to October 2024), kWh and kW due to changes completed for RRR reporting (referenced in SC-VECC-5.0) and billing adjustments related to 2023 and 2024 completed in subsequent years.

As a result of the changes related to item II, Hydro Ottawa has updated Appendix-2R - Loss Factor. Please find this update attached as Attachment SC-VECC-16(A) - Appendix 2R. This update has resulted in a decrease to the loss factor.

In addition, Hydro Ottawa has updated the 2024 true-up values with billing adjustments for Accounts 1588 and 1589 as presented in the Deferral and Variance Accounts (Continuity Schedule). This has resulted in a reduction of the amount to be collected for these accounts. Please see Attachment SC-VECC-16(B) - OEB Workform - 2026 Deferral and Variance Accounts (Continuity Schedule) and Attachment SC-VECC-16(C) - OEB Workform - 2026 Commodity Accounts Analysis. These updates will also separately be put on the public record.

Please see Tables A, B and C below with 2026-2030 updated proposed revenue load and customer forecast.

Table A - Revised 2026-2030 Proposed Revenue Energy Forecast by Customer Class (MWh)[1]

	2026	2027	2028	2029	2030
Residential	2,601,494	2,628,618	2,663,642	2,682,208	2,713,673
General Service < 50 kW	722,556	722,196	724,707	722,940	722,437
General Service 50 to 1,000 kW	2,461,496	2,453,652	2,453,708	2,442,562	2,434,844
General Service 1,000 to 1,499 kW	371,336	360,958	352,631	350,782	349,352
General Service 1,500 to 4,999 kW	724,076	716,917	711,701	703,671	696,408
Large Use	527,869	550,538	597,264	650,551	684,717
Street Lighting	21,962	22,060	22,158	22,257	22,355
Unmetered Scattered Load	14,392	14,472	14,552	14,633	14,713
Sentinel Lighting	41	40	39	38	38
TOTAL MWh SALES	**7,445,221**	**7,469,450**	**7,540,402**	**7,589,641**	**7,638,537**

[1] This forecast does not include the Dry Core Transformer Charge. Totals may not sum due to rounding.

Table B – 2026-2030 Proposed Revenue Load Demand Forecast by Customer Class (kW)

	2026	2027	2028	2029	2030
General Service 50 to 1,000 kW Interval	6,203,070	6,183,449	6,183,548	6,155,649	6,136,293
General Service 1,000 to 1,499 kW	787,369	767,238	752,499	748,542	745,513
General Service 1,500 to 4,999 kW	1,612,599	1,595,891	1,583,717	1,564,977	1,548,024
Large Use	934,731	1,001,126	1,133,197	1,304,010	1,413,374
Street Lighting	61,129	61,402	61,676	61,949	62,184
Sentinel Lighting	120	114	108	108	108
Standby Power	44,837	44,475	44,248	43,751	43,353
TOTAL KW DEMAND SALES	**9,599,018**	**9,609,220**	**9,714,745**	**9,835,235**	**9,905,496**

Table C - 2026-2030 Proposed Monthly Average Number of Customers by Class[2]

	2026	2027	2028	2029	2030
Residential	348,287	351,762	355,313	358,968	362,676
General Service < 50 kW	26,031	26,153	26,278	26,406	26,536
General Service 50 to 1,000 kW	3,061	3,061	3,061	3,061	3,061
General Service 1,000 to 1,499 kW	88	89	90	91	93
General Service 1,500 to 4,999 kW	70	69	69	69	69
Large Use	11	12	13	14	14
Standby Power	6	6	6	6	6
TOTAL CUSTOMERS	**377,554**	**381,152**	**384,830**	**388,615**	**392,455**

Table D - 2026-2030 Proposed Monthly Average Number of Connections by Class

	2026	2027	2028	2029	2030
Street Lighting	65,914	66,825	67,736	68,647	69,558
Unmetered Scattered Load	4,263	4,383	4,503	4,622	4,742
Sentinel Lighting	47	46	45	44	43
TOTAL CONNECTIONS	**70,224**	**71,254**	**72,284**	**73,313**	**74,343**

[2] Totals may not sum due to rounding.

The request was also to update interrogatories 3.0-VECC-21 to 3.0-VECC-27. The necessary updates will be provided when they become available.

Hydro Ottawa has provided the following updated Excel Attachments for the updated revenue load and customer forecast detailed above. Please note as part of the updated revenue load forecast, one of the reclassified customers was not included in the customer count change, and as a result the GS 1500-4999 count should have been 71.

- Attachment SC-VECC-16(D) - Updated 3.0-VECC-15-A - GS and LU Count Forecast
- Attachment SC-VECC-16(E) - Updated 3.0-VECC-22-A - GS 1000 Sales Forecast
- Attachment SC-VECC-16(F) - Updated 3.0-VECC-22-B - GS 1500 Sales Forecast
- Attachment SC-VECC-16(G) - Updated 3.0-VECC-22-A - GS 5000 Sales Forecast
- Attachment SC-VECC-16(H) - Updated 3.0-VECC-22-A - LU Sales Forecast

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-17

EVIDENCE REFERENCE:
Attachment JT1.14-VECC-6.0(C) - Revised Large Load Electrification kW by Month
Attachment JT1.14-VECC-6.0(D) - Original Large Load Electrification kW by Month

QUESTION(S): Attachments JT1.14-VECC-6.0(C) and JT1.14-VECC-6.0(D) do not net out to zero. HOL to check and reconcile.

RESPONSE(S):

Hydro Ottawa confirms the Attachment JT1.14-VECC-6.0(C) - Revised Large Load Electrification kW by Month does not reflect the intended update. When reviewing the files it was noticed an incorrect adjustment was made to eliminate the double counting move issues.

Hydro Ottawa is working on an updated load forecast to correct this issue and will provide an updated Attachment JT1.14-VECC-6.0(C).

SETTLEMENT RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

SC-VECC-18

EVIDENCE REFERENCE:

3-SEC-62(A)

QUESTION(S):

Given the noted change to the October 2024 actual customer counts by class, could you please update the response to 3-SEC 62(A) which provided the actual customer count by class from Nov 2024 to June 2025 but also include the revised values for October 2024.

RESPONSE(S):

Please see Excel Attachment SC-VECC-18(A) - Updated 3-SEC-62(A) - Bill Determinants Customer Count Actuals - Oct 2024-June 2025 for an updated Attachment 3-SEC 62(A), which originally provided the month end customer count by class for November 2024-June 2025. The new Attachment includes the revised values for October 2024 as requested.