

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-101**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 7 / p. 73 (pdf Exhibit 2 part 4, p. 271)

8
9 **QUESTION(S):**

10
11 a) Figure 38 - Number of Poles Projected to Reach a Deteriorated Condition by 2030, shows 2024
12 (10%), Pole alternative 1 (10%), 2 (9%), and 3 (8%) and 2030 no investment (12%). What is the
13 "deteriorated condition" threshold: very poor, poor, fair or other criteria?

14
15 **RESPONSE(S):**

16
17 a) The "deteriorated condition" threshold is for poles anticipated to be in Poor and Very Poor
18 condition by 2030.

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3 **2-Staff-102**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 7 / p. 91 (pdf Exhibit 2 part 4, p. 289)

8
9 Preamble:

10 Figure 49 - Condition Profile of UG Transformers, shows the Condition Profile for 2024, 2030, 2035,
11 and 2040 for underground (UG) distribution transformers.

12
13 **QUESTION(S):**

- 14
15 a) Please confirm that with no investment, 1% of UG transformers are projected to be in very poor
16 condition by 2040.
17 b) What is the annual failure probability of UG transformers assessed to be in poor condition?
18 c) What is the annual failure probability of UG transformers assessed to be in very poor condition?

19
20
21 **RESPONSE(S):**

22
23 a) Yes, 1% of UG transformers are projected to be in very poor condition by 2040, based on the
24 projections from Copperleaf Predictive Analytics (PA) and the existing condition data for UG
25 transformers (in 2024). The condition information for UG transformers is evolving based on the
26 inspection enhancements in 2024 and will inform future management of UG transformers and
27 their condition assessment.

28
29 b) In 2024, Hydro Ottawa collaborated with Hatch to improve its understanding of asset failure
30 curves. The goal was to enhance the utility's risk-based and value-based asset management
31 framework. Hatch utilized statistical methods to analyze Hydro Ottawa's data, creating a

1 simulated asset population that accurately mirrored Hydro Ottawa's actual asset registry. This
2 analysis primarily focused on determining the most suitable Weibull curve parameters (a
3 combination of shape and scale values), which is a standard industry approach for developing
4 failure curves. As a part of the failure curve development process, the Cumulative Distribution
5 Function (CDF) was developed by Hatch, which represents the probability that an asset will fail
6 by or at a specific time, effectively showing the cumulative probability of failure over time. More
7 information regarding the failure curves initiative is shown in Section 4.4.4 Failure Curves and
8 Typical Useful Life Update under Schedule 2-5-4 - Asset Management Process.

9
10 Hydro Ottawa's methodology for calculating the annual probability of failure (PoF) for specific
11 asset condition categories is based on the exponential CDF. This methodology considers a
12 constant failure rate (λ) for a given asset type based on the underlying failure curve.

13
14 The formula used is:

$$15 \text{ PoF} = 1 - e^{-\lambda t}$$

16
17 As per Hydro Ottawa's current underground transformer condition failure probability curve, the
18 overall probability of failure for underground transformers in a Poor condition is 0.0687 (λ). For
19 the annual PoF, the time variable (t) is set to 1 year. Applying this to the annual PoF formula, the
20 annual probability of failure can be obtained as shown below:

$$21 \text{ Annual PoF} = 1 - e^{-0.0687} \approx 0.0664$$

22
23
24 c) Hydro Ottawa's methodology for calculating the annual probability of failure (PoF) for specific
25 asset condition categories is based on the exponential CDF. This methodology considers a
26 constant failure rate (λ) for a given asset type based on the underlying failure curve. The
27 formula used is:

$$28 \text{ PoF} = 1 - e^{-\lambda t}$$

1 As per Hydro Ottawa's current underground transformer condition failure probability curve, the
2 overall probability of failure for underground transformers in a Very Poor condition is 0.0902 (λ).
3 For the annual PoF, the time variable (t) is set to 1 year. Applying this to the annual PoF
4 formula, the annual probability of failure can be obtained as shown below:

5

6

$$\text{Annual PoF} = 1 - e^{-0.0902} \approx 0.0863$$

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3 **2-Staff-103**

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5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 7 / p. 98 (pdf Exhibit 2 part 4, pp. 296)

8
9 **QUESTION(S):**

10
11 a) Figure 56 - Condition Profile of Vault Switchgear (excl. customer-owned), shows the Condition
12 Profile for 2024, 2030, 2035, and 2040 for vault switchgear. Please explain why the percentage
13 of vault switchgear in very poor condition will remain steady at 5% until 2040 with no
14 investment.

15
16

17 **RESPONSE(S):**

18
19 a) With no investment, the percentage of vault switchgear in very poor condition will remain steady
20 at 5% until 2040 because the projections out to 2040 are based on condition data available in
21 2024. Hydro Ottawa advanced its vault equipment inspection program in 2024 to capture
22 component-level information and continues to prioritize proposed inspection enhancements
23 through 2026-2030, as detailed in Section 3.1 of Schedule 4-1-2 - Operations, Maintenance and
24 Administration Program Costs. As condition data matures over the coming years, the
25 demographics will evolve, and Hydro Ottawa will adjust future plans and recommended
26 investment levels accordingly.

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3 **2-Staff-104**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 7 / p. 105 (pdf Exhibit 2 part 4, p. 303)

8
9 **Preamble:**

10 Hydro Ottawa states that the Cable Renewal Program budget will increase from \$54.3M
11 (2021–2025) to \$88.2M (2026–2030) due to higher unit costs driven by inflation and project
12 complexity, with a new rate of \$1.4M/km. Between 2026 and 2030, cable replacements will be
13 prioritized across 12 key feeder areas based on results from underground cable testing.

14
15 **QUESTION(S):**

- 16 a) Does Hydro Ottawa’s cable renewal program include cable injections?
17 i) If not, please explain what technical, economic, or reliability factors led to the exclusion
18 of this approach.
19 ii) If so, please describe the scope of work planned and the annual costs for the forecast
20 period.

21
22
23 **RESPONSE(S):**

- 24
25 a) No, Hydro Ottawa’s cable renewal program does not include cable injections.
26
27 i) Hydro Ottawa previously implemented a cable injection program, based on a pilot in
28 2013 and field application from 2015-2019, with at least 20 km of cable injected. Cable
29 injection was later discontinued due to limited observed benefits and increasing costs.
30 Experience showed multiple outages and failures in the initial years post-injection, with
31 other challenges such as cable vintage and strand blocking, customer outages with live

1 front transformers and injecting cables with splices. This decision was primarily driven by
2 the understanding that underground cable systems are susceptible to various failure
3 modes, including concentric neutral corrosion, partial discharge (in elbows, splices, and
4 cable insulation), and water treeing in the cable insulation, not all of which are addressed
5 by cable injection. Discussions with peer utilities also indicated a lack of similar benefits.
6 Furthermore, the cost of cable injections significantly increased around 2022-2023,
7 making the program cost-prohibitive with minimal value.

8

9 ii) Not Applicable.

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3 **2-Staff-105**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 7 / p. 125 (pdf Exhibit 2 part 4, p. 323)

8
9 **Preamble:**

10 Hydro Ottawa states that its metering fleet is vital for accurate billing, regulatory compliance, and
11 effective grid management, with smart meter deployment beginning in 2006 and completing
12 replacement of over 277,000 meters by 2011.

13
14 **QUESTION(S):**

- 15
16 a) What are the TULs for electromechanical meters and electronic smart meters?
17 b) Please provide evidence to support the TUL of the electronic smart meters.
18 c) Has Hydro Ottawa investigated any meter technology alternatives that will provide the AMI 2.0
19 functionality with a longer TUL?
20 d) What options has Hydro Ottawa investigated to extend the service lives of the existing smart
21 meter fleet?
22 e) Do the AMI 2.0 meters have onboard self-diagnostic capability?

23
24

25 **RESPONSE(S):**

26
27 a) The typical useful life (TUL) of an electronic smart meter is 15 years, as outlined in Schedule
28 2-5-7 - System Renewal Investments, Figure 72, page 129. Hydro Ottawa completed the
29 removal of all electromechanical meters from its service territory in 2011 and consequently has
30 no data on its TUL.

- 1 b) Based on Hydro Ottawa’s capitalization policy, the useful life of a revenue meter is set to 15
2 years. Meter manufacturers have conducted accelerated life testing and have stated that the
3 useful life of a meter is 25 years. However, they are unable to support their claim with
4 documentation. These accelerated life tests do not account for technological obsolescence,
5 which is the primary driver for increasingly shortened lives of the meters.
6
- 7 c) No, Hydro Ottawa has not investigated any meter technology alternatives that will provide the
8 AMI 2.0 with a prolonged TUL. Hydro Ottawa must use meters approved by Measurement
9 Canada, and is unaware of any meter technology alternatives approved by Measurement
10 Canada for electricity revenue metering.
11
- 12 d) Hydro Ottawa’s considered alternatives are outlined in section 5.6.1 of Schedule 2-5-7 - System
13 Renewal Investments. Hydro Ottawa is limited to extending the service life of a meter using
14 Measurement Canada’s seal extension provisions under S-S-06 - Sampling plans for the
15 inspection of isolated lots of meters in service. S-S-06 is a regulated method to extend the total
16 useful life of a meter used by all local distribution companies. However, it cannot indefinitely
17 prolong meter life, as it has regulatory limits and does not account for technological
18 obsolescence. Hydro Ottawa’s fleet would be at the limit of the 2-year required sampling at the
19 end of the rate period if Alternative 1 were selected.
20
- 21 e) Yes, the AMI 2.0 meters will have onboard self-diagnostic capability. On-board diagnostic
22 capabilities vary by meter manufacturer and configuration, and the minimum diagnostics
23 requirements are part of the Government of Ontario’s “Functional specification for an advanced
24 metering infrastructure.”

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3 **2-Staff-106**

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5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 1 (pdf Exhibit 2 part 4, p. 365)

8
9 **Preamble:**

10 Hydro Ottawa states “The Enhancements program supports DER integration through infrastructure
11 upgrades and pilot projects, leveraging federal funding for innovation.”

12
13 **QUESTION(S):**

- 14
15 a) What is the forecast test period spending for the Distribution Enhancements program?
16 b) Will any of this spending be stranded if DER additions are lower than forecast?

17
18
19 **RESPONSE(S):**

- 20
21 a) As per Table 7 in Section 3.5 of Schedule 2-5-8 - System Service Investments, the spend for the
22 Distribution Enhancements Budget Program, as a part of the Distribution Enhancement Capital
23 Program, is expected to total \$20.3M over the 2026-2030 period.
24
25 b) The spending under the Distribution Enhancement program is specifically allocated to projects
26 that will prepare Hydro Ottawa's distribution system to effectively leverage demand-side
27 resources through Distributed Energy Resource (DER) enablement. Further details on these
28 initiatives can be found in Section 3.6.3 of Schedule 2-5-8 - System Service Investments.

1 It is crucial to note that this funding is not directly linked to new DER additions. The facilitation of
2 new DER connections are handled separately through the Generation Connections program
3 (Section 5 of Schedule 2-5-6 - System Access Investments).

4
5 Consequently, Hydro Ottawa does not anticipate any stranded investments under the
6 Distribution Enhancement program, even if DER additions are lower than forecast. The nature
7 of these enhancement projects is to build foundational capabilities and infrastructure for DER
8 integration, rather than being dependent on a specific volume of new DER connections.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

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3 **2-Staff-107**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 3 (pdf Exhibit 2 part 4, p. 367)

8
9 **QUESTION(S):**

10
11 a) Hydro Ottawa states “Driven by system efficiency, the FAN enables real-time data access for
12 grid modernization and DER integration, strengthens cyber security, and improves outage
13 response by providing grid visibility and control.” Please identify and quantify any future O&M
14 cost savings attributable to the system efficiency improvements that will be delivered by FAN.

15
16
17 **RESPONSE(S):**

18
19 a) Hydro Ottawa acknowledges that the phrasing of the statement may have inadvertently
20 misrepresented the relationship between the investment in the FAN (Field Area Network) and
21 system efficiency. The utility recognizes that the statement could be interpreted to mean that
22 system efficiency is a direct and immediate outcome of the FAN itself.

23
24 To clarify, the investment in the FAN is not the direct cause of system efficiency improvements.
25 Rather, the FAN is an enabling technology that provides the necessary infrastructure for other
26 programs and initiatives that will, in turn, deliver system efficiency. Specifically, the FAN provides
27 the foundational capabilities—such as real-time data access and grid visibility—that are
28 essential for the programs listed below, ensuring the continuous, high-availability
29 communication essential for Hydro Ottawa's evolving grid.

1 **Distribution Enhancements Program:** The FAN supports advanced grid devices such as Fault
2 Circuit Indicators (FCIs) and Smart Switches. Section 3 of Schedule 2-5-8 - System Service
3 Investments details how these devices enable faster fault localization, remote operations, and
4 quicker service restoration. The program's drivers and needs are detailed in Section 3.3 of that
5 Schedule, including the primary driver and secondary drivers.

6
7 **Capacity Upgrade Programs:** These programs involve significant investments in expanding
8 and building new substations. Constructing new substations necessitates the installation of new
9 fiber optic segments, while expanding existing substations requires additional wireless
10 connectivity. The FAN enables the monitoring of these substations and ensures the highest
11 availability for critical applications like SCADA (Supervisory Control and Data Acquisition) and
12 Transfer Trip. Section 2 of Schedule 2-5-8 - System Service Investments outlines the substantial
13 investments in substation expansion and construction. The program's drivers and needs are
14 detailed in Section 2.3 of that Schedule, including the primary driver and secondary drivers.

15
16 **Control and Optimization Program:** The FAN enables the Distributed Energy Resource
17 Management System (DERMS), which is crucial for managing the increasing complexity of
18 Distributed Energy Resource (DER) integration. Section 7 of Schedule 2-5-8 - System Service
19 Investments elaborates on the implementation and necessity of DERMS for managing the
20 growing integration of DERs. The program's drivers and needs are detailed in Section 7.3 of that
21 Schedule, including the primary driver and secondary drivers.

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5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 5 (pdf Exhibit 2 part 4, p. 369)

8
9 **Preamble:**

10 Hydro Ottawa presents, in the System Service Program Summary under Capacity Upgrade, a
11 program cost increase from \$108.2M (2021-2025) to \$365.9M (2026-2030), “\$342.6 Net Capex,
12 \$13.3M (OM&A) \$10.0M (Costs included in Other Income and Deductions)”, for the Station
13 Capacity Upgrades, Distribution Capacity Upgrades, Non-Wire Upgrades Budget Program.

14
15 **QUESTION(S):**

- 16
17 a) Proposed spending on this program is more than triple historical levels. Did the Historical/Bridge
18 period spending levels fail to deliver necessary capacity expansion? Please discuss.
- 19 b) What proportion of the proposed Capacity Upgrade spending will be stranded or unnecessary if
20 compounding load growth over the test period turns out to be similar to the Historical/Bridge
21 period levels?
- 22 c) Please identify each event over the Historical/Bridge period during which Hydro Ottawa had
23 inadequate capacity to serve loads after implementing available sectionalizing and backup
24 options and quantify the load that could not be served and the duration of the inability to serve it
25 for each event.

26
27
28 **RESPONSE(S):**

- 29
30 a) The Historical/Bridge period spending did not fail to deliver necessary capacity expansion.
31 Proposed spending for the Capacity Upgrade program for 2026-2030 increased due to a surge

- 1 in committed loads and existing capacity constraints, a trend exacerbated by electrification. This
2 highlights the urgent need to expand the system's capacity to handle these new connections,
3 which in turn raised the program's funding requirements.
4
- 5 b) The proposed capacity upgrade spending in the 2026-2030 period will not be stranded or
6 unnecessary if compounding load growth over the test period turns out to be similar to the
7 Historical/Bridge period levels. This is because forecasted system capacity and associated
8 capacity upgrade spending is not directly linked to compounding load growth but rather based
9 on immediate needs of the system focused on already constrained regions and areas with
10 immediate, confirmed, and committed load requirements necessary to meet customer service
11 obligations.
12
- 13 c) There were no instances during the Historical/Bridge period where Hydro Ottawa was unable to
14 serve loads after implementing available sectionalizing and backup options. During the
15 2026-2030 period, to ensure this continued level of service, Hydro Ottawa is leveraging NWS to
16 support in regions with immediate capacity requirements. Refer to Section 9.2 of Schedule 2-5-4
17 - Asset Management Process.

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3 **2-Staff-109**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 7 (pdf Exhibit 2 Part 4, p. 371)

8
9 **Preamble:**

10 In the application, Hydro Ottawa proposes two major investments under the Distribution System
11 Upgrade program, including the following:

- 12 • The feeder integration will support the reduction of load on some of the highly loaded stations,
13 such as Kanata MTS, Marchwood MTS, and Lietrim DS
14 • Introduction of 28kV in the capacity constrained Nepean 8kV system

15
16 **QUESTION(S):**

- 17 a) For these two major investments, please describe if Hydro Ottawa considered non-wires
18 solutions to address these system needs.
19 i) If yes, please clarify the system need and the results of Hydro Ottawa's NWS
20 consideration.
21 ii) If not, please explain why NWSs were not considered.

22
23
24 **RESPONSE(S):**

25
26 The following responses refer to the proposed investments with the Distribution Capacity Upgrade
27 budget program, within Capacity Upgrade Capital Program.

- 28
29 a) Hydro Ottawa considered Non Wire Solutions (NWS) to address the system capacity needs
30 outlined in the preamble, with the exception of Lietrim DS as this need was identified in the

1 previous application. The assessment criteria for NWS is detailed in Section 9.2.1 of Schedule
2 2-5-4 - Asset Management Process.

3 i) System Need:

- 4 ● The needs for the Distribution Capacity Upgrade investments for Kanata MTS,
5 Marchwood MTS, and Leitrim MS (listed as Feeder Integration for Piperville
6 MTS), are provided in Section 2.3.2.2 of Schedule 2-5-8 - System Service
7 Investments.
- 8 ● The needs in the Nepean 8kV system (Greenbank MTS) are described within
9 Section 2.3.2.1 starting on page 21 of Schedule 2-5-8 - System Service
10 Investments.
- 11 ● Details on the Non-Wires program needs are outlined in Section 2.3.2.3 of
12 Schedule 2-5-8 - System Service Investments.

13
14 NWS Assessment Results:

15 Results of Hydro Ottawa's NWS assessment, for the regions outlined in the preamble,
16 determined the viability of Non-Wire Customer Solutions programs in the West 28kV
17 (North) region supplied by Kanata and Marchwood, and a utility-owned BESS in the
18 Nepean 8kV region - Bell Corners/ Bayshore. More details of the needs can be found in
19 Section 9.2.3.1 and Section 9.2.3.3 of Schedule 2-5-4 - Asset Management Process.

20
21 ii) Not Applicable.

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5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 7 (pdf Exhibit 2 part 4, p. 371)

8
9 **QUESTION(S):**

10
11 a) Hydro Ottawa mentions “transit development and large infrastructure projects such as the new
12 Ottawa Hospital campus” contributed to load growth. Please explain why expansions for transit
13 and large infrastructure projects are not categorized as System Access spending.

14
15
16 **RESPONSE(S):**

17
18 a) The statement regarding "transit development and large infrastructure projects such as the new
19 Ottawa Hospital campus" contributing to load growth was a generic observation highlighting
20 general growth in the downtown core. Any specific expansions for large infrastructure projects
21 or transit that are driven by direct customer servicing requests will be categorized as System
22 Access spending. These projects will also undergo the Ontario Energy Board’s (OEB)
23 prescribed economic evaluation methodology. For further details on Hydro Ottawa's system
24 expansion processes and their drivers, please refer to Section 4 of Schedule 2-5-6 - System
25 Access Investments.

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3 **2-Staff-111**

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5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 8 (pdf Exhibit 2 part 4, p. 372)

8 Ref. 2: Exhibit 2 / Tab 5 / Schedule 4 / pp. 283-287 (pdf Exhibit 2 Part 3, pp. 283-287)

9 Ref. 3: Exhibit 2 / Tab 5 / Schedule 8 / pp. 33-34 (pdf Exhibit 2 Part 4, pp. 397-398)

10
11 **Preamble:**

12 Hydro Ottawa presents 4 BESS projects: 2.5MW BESS in the West 28 kV system, 7MW BESS in
13 the Bells Corners/Bayshore 8 kV system, 5MW BESS at Casselman DS, 10MW BESS in the Core
14 13 kV/West 13kV system.

15
16 **QUESTION(S):**

17
18 a) What is the all-in unit cost per MW and per MWh of each of these BESS installations?

19 b) What are the forecast capacity utilizations of each of these BESS installations?

20 c) Please clarify the following related to each of the 4 BESS:

21 i) The specific system need that is being addressed by each BESS

22 ii) The specific region(s) where each of the 4 BESS will be used

23 iii) The anticipated cost (in total and annually from 2026-2030) and the type of cost (capital
24 expenditure or OM&A) for each BESS. See Table 3 below for guidance.

25 iv) The major activities and their associated timelines for each BESS

26 d) Please provide the cost-benefit analyses for each of these BESS installations.

27 e) Please complete Table 4 below for the 4 BESS, providing the following details for each BESS
28 and their corresponding traditional infrastructure solution:

29 i) Quantitative and qualitative benefits (including avoided/deferred costs)

30 ii) Quantitative and qualitative costs

- 1 iii) Any calculations Hydro Ottawa has completed to evaluate the cost-effectiveness of each
- 2 of the 4 BESS over traditional wire solutions, if any
- 3 f) Please confirm Hydro Ottawa’s expertise in setting up, connecting, operating, and maintaining a
- 4 utility-owned BESS, responding to the following:
- 5 i) If in-house expertise is currently not present, please describe how Hydro Ottawa plans to
- 6 secure this expertise and any associated costs (OM&A) to set up, connect, operate,
- 7 and/or maintain a utility-owned BESS.
- 8 ii) What other options did Hydro Ottawa consider (if any) to support the excess demand in
- 9 the near term for each of the four areas, and why was a utility-owned BESS determined
- 10 to be the best option for each area?
- 11 g) How does Hydro Ottawa plan to leverage the learnings and/or 4 BESS capital assets once each
- 12 BESS has helped meet the intended system need in the 4 areas?
- 13 h) Please provide details on when and how Hydro Ottawa intends to use each BESS assets.

Table 3: Breakdown of Costs (BESS)

NWS Program	Cost Category	Cost				
		2026	2027	2028	2029	2030
West 28 kV	Capital					
	OM&A					
Bells Corners/ Bayshore 8 kV	Capital					
	OM&A					
Casselman 8 kV	Capital					
	OM&A					
Core 13 kV, West 13 kV	Capital					
	OM&A					

16

1
2

Table 4: Benefits and Costs of BESS

Category	BESS in West 28 kV	BESS in Bells Corners/ Bayshore 8 kV	BESS in Casselman 8 kV	BESS in Core 13 kV, West 13 kV
Benefits				
A. Quantitative (\$)				
A. Explanation				
B. Qualitative				
B. Explanation				
Costs				
C. Quantitative (\$)				
C. Explanation				
D. Qualitative				
D. Explanation				

3
4

RESPONSE(S):

6

a) As each of the proposed BESS projects are currently in their initial scoping phase, Hydro Ottawa has estimated a high-level capital cost based off of \$2.5M/MW for a 4-hour system at \$625k/MWh. This estimate was derived from Newfoundland and Labrador Hydro's "Battery Energy Storage System Report," dated September 29, 2023.¹

11

b) The capacity utilization for each BESS is as outlined in the preamble, and shown in Section 2.1, page 8, of Schedule 2-5-8 - System Service Investments.

14

c)

16

i) For details on the specific system needs that each BESS addresses, refer to Section 2.3.2.3 of Schedule 2-5-8 - System Service Investments:

17

18

- 2.5MW BESS in the West 28 kV system - starting on page 34 - "West 28kV system"

19

- 7MW BESS in the Bells Corners/Bayshore 8 kV system - starting on page 37 - "Bells Corners/Bayshore 8kV system"

20

¹ Newfoundland and Labrador Hydro, [Battery Energy Storage System Report](#) (September 29, 2023).

- 1 ● 5MW BESS at Casselman DS - starting on page 40 - “Casselman 8kV system”
- 2 ● 10MW BESS in the Core 13 kV/West 13kV system - starting on page 44 - “Core
- 3 13kV and West 13kV system”
- 4
- 5 ii) Please refer to the response to part (c)(i).
- 6 iii) Please refer to Table A below for the forecast cost for each BESS. The OM&A costs
- 7 cannot be split by BESS, as the budget is for annual maintenance of all BESS
- 8 installations.
- 9
- 10 ● For an overview of forecasted expenditure by Capital Program and by OM&A
- 11 Program please see Section 2.5.3 of Schedule 2-5-8 - System Service Investments.
- 12 ● For additional details on the capital program, please see Section 5.3.3 of Schedule
- 13 2-5-5 - Capital Expenditure Plan.
- 14 ● For additional details on the OM&A program, please see Section 3.1 of Schedule
- 15 4-1-2 - Operations, Maintenance and Administration Program Costs.
- 16
- 17

Table A - Breakdown of BESS Costs (\$'000s)

BESS Project	Cost Category	Test Years				
		2026	2027	2028	2029	2030
West 28 kV	Capital	\$ 4,100	\$ 2,000	\$ 150	\$ -	\$ -
Bells Corners/Bayshore 8 kV	Capital	\$ -	\$ 5,950	\$ 5,650	\$ 5,900	\$ -
Casselman 8 kV	Capital	\$ -	\$ 6,000	\$ 6,500	\$ -	\$ -
Core 13 kV, West 13 kV	Capital	\$ -	\$ -	\$ 7,900	\$ 8,350	\$ 8,700
All BESS	OM&A	-	-	\$ 20	\$ 20	\$ 20

- 18
- 19 iv) Hydro Ottawa would like to make a correction to pages 35, 38, 41, and 44 of Schedule
- 20 2-5-8 - System Service Investments where it states that all BESS will energize in 2030.
- 21 Please see Table B for major activities, their associated timelines, and the proposed
- 22 energization date for each BESS project.

1 **Table B: Breakdown of BESS Major Activities**

BESS Project	Major Activities				
	2026	2027	2028	2029	2030
West 28 kV	Design & Procurement	Construction	Commissioning & Energization		
Bells Corners/ Bayshore 8 kV		Design & Procurement	Construction	Commissioning & Energization	
Casselman 8 kV		Design, Procurement & Construction Kick-Off	Construction, Commissioning & Energization		
Core 13 kV, West 13 kV			Design & Procurement	Construction & Commissioning	Energization

2
 3 d) Hydro Ottawa conducted a pre-assessment based on the NWS assessment criteria as outlined
 4 in section 9.2.1 of Schedule 2-5-4 - Asset Management Process and determined the viability of
 5 NWS within the four areas as presented. Based on the timing and magnitude of capacity
 6 requirements within these areas, Hydro Ottawa noted that the challenge of ensuring reliability of
 7 supply through traditional wires solutions to be not economically feasible, and as such the BESS
 8 solution is the reference scenario. As outlined in the OEB's BCA Framework² under section
 9 3.2.2. Discretionary vs. Non-Discretionary System Need on page 16, when the NWS becomes
 10 the reference scenario "...undertaking a BCA might be neither appropriate, nor necessary". As
 11 per the guidance, Hydro Ottawa has not completed a BCA and has provided a cost estimate of
 12 a potential traditional poles and wires option as presented in Table C.

²https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-05/OEB_BCA_Framework_FINAL-AODA.pdf

1

Table C: Benefits and Costs of BESS

Category	BESS in West 28 kV	BESS in Bells Corners/ Bayshore 8 kV	BESS in Casselman 8 kV	BESS in Core 13 kV, West 13 kV
Benefits				
A. Quantitative (\$)	\$12M distribution extension cost	\$45M+ new station cost	\$32M+ new station cost	\$45M+ new station cost
	2.5MW of capacity	7MW of capacity	5MW of capacity	10MW of capacity
A. Explanation	Estimated \$12M cost to extend an additional feeder (11km) from a Hydro One station.	Cost to build a new 28kV station (\$45M), voltage conversion of the existing 8kV feeders (unknown) and potential transmission upgrades (unknown).	Avoided cost to build a new 8kV station (\$30M) and integrate 4 feeders (\$2M). A new station would require transmission upgrade (cost unknown)	Avoided cost to build a second 13kV station (\$45M) in the Core 13kV, West 13kV plus upgrading the 115kV transmission lines and upgrade Hawthorne TS (cost unknown)
	The Beckwith feeder is currently exceeding its planning capacity with limited connection to other feeders in the area. Considering the IRRP forecast, the station will be overloaded by 5MVA by 2025. After some load transfers to adjacent stations, the additional capacity from the BESS will alleviate these anticipated constraints.	Both 8kV stations in the area are approaching planning capacity. Considering the IRRP forecast, the area will be overloaded by 10MVA by 2035. The additional capacity from the BESS will alleviate these anticipated constraints while electrification uptake is monitored.	Casselman DS is projected to exceed its station and feeder capacity by 2030. Considering the IRRP forecast, the station will be overloaded by 5 MVA by 2035. The BESS will alleviate these anticipated constraints.	The region will exceed its planning capacity in 2028. Considering the IRRP forecast, a second station will be needed by 2035. Along with the construction of a new station (Bronson 13kV) and proposed Non-Wires Customer Solutions for this area, the installation of 10MW BESS will defer the need for a second station and associated 115kV transmission upgrades.

Category	BESS in West 28 kV	BESS in Bells Corners/ Bayshore 8 kV	BESS in Casselman 8 kV	BESS in Core 13 kV, West 13 kV
B. Qualitative	-Improved reliability -Manages peak load and enhances grid flexibility	-Improved reliability -Manages peak load and enhances grid flexibility	-Improved reliability -Manages peak load and enhances grid flexibility	-Improved reliability -Manages peak load and enhances grid flexibility
B. Explanation	The Beckwith feeder is currently exceeding its planning capacity. By alleviating capacity limitations and offering localized grid support, the BESS directly contributes to enhancing overall grid reliability.	Based on the planning forecast, capacity will be exceeded by 2030 at Bayshore DS and Q.C.H DS. By alleviating capacity limitations and offering localized grid support, the BESS directly contributes to enhancing overall grid reliability.	Based on the planning forecast, capacity will be exceeded by 2030 at Casselman. By alleviating capacity limitations and offering localized grid support, the BESS directly contributes to enhancing overall grid reliability. Additionally, it enhances the reliability of the single-transmission supply station, which is currently isolated from other Hydro Ottawa stations for backup ties.	The planning forecast of the core and west 13.2 kV sub-section is anticipated to exceed the planning capacity by 2028 without intervention, even earlier if customer load inquiries come to fruition. By alleviating capacity limitations and offering localized grid support, the BESS directly contributes to enhancing overall grid reliability and defers the need for a second station and associated transmission upgrades.

Category	BESS in West 28 kV	BESS in Bells Corners/ Bayshore 8 kV	BESS in Casselman 8 kV	BESS in Core 13 kV, West 13 kV
Costs				
C. Quantitative (\$)³	\$6.25M - BESS cost	\$17.5M - BESS cost	\$12.5M - BESS cost	\$25M - BESS cost
	\$5.75M - Avoided capex	\$27.5M+ - Avoided capex	\$19.5M+ - Avoided capex	\$20M+ - Avoided capex
C. Explanation	\$6.25M \$2.5M/MW for a 2.5MW battery	\$17.5M \$2.5M/MW for a 7 MW battery	\$12.5M \$2.5M/MW for a 5MW battery	\$25M \$2.5M/MW for a 10MW battery
	Distribution extension cost (A.) minus the BESS cost	New station cost (A.) minus the BESS cost	New station cost (A.) minus the BESS cost	New station cost (A.) minus the BESS cost

1

³ Quantitative assessment compares capital expenditures of BESS vs capital expenditures avoided, it does not factor in depreciation impacts or revenue requirement.

- 1 e) As outlined in Section 9.2.1 of Schedule 2-5-4 - Asset Management Process, the NWS,
2 including BESS, are not expected to cause substantial avoidance or deferral of the identified
3 wire capacity investment needs. They will play a crucial role in moderating the pace of system
4 demand growth and enhancing reliability in the 2026-2030 period, while continuing to support
5 the grid in the long term.
- 6 i) Please refer to Table C above for qualitative and quantitative benefits. Additionally,
7 please refer to Section 2.4.1 of Schedule 2-5-8 - System Service Investments for further
8 details on qualitative benefits.
- 9 ii) Please refer to Table C for costs.
- 10 iii) Refer to Table C for the comparison of traditional wire solution costs and calculated
11 avoided costs. For detailed comparisons of BESS solutions against traditional wired
12 alternatives, refer to the following sections in Schedule 2-5-8 - System Service
13 Investments:
- 14 ● West 28kV BESS: Section 2.3.2.3, page 37
 - 15 ● Bayshore 8kV BESS: Section 2.3.2.3, page 40
 - 16 ● Casselman BESS: Section 2.3.2.3, page 43
 - 17 ● Core West BESS: Section 2.3.2.3, page 46
- 18 f)
- 19 i) To acquire expertise in BESS system installations, Hydro Ottawa will adopt a
20 multi-pronged approach that includes developing internal capabilities through dedicated
21 training for staff in BESS fundamentals, installation, commissioning, operations, and
22 safety protocols, especially regarding fire prevention and emergency response. At
23 present, Hydro Ottawa is gaining practical experience and building in-house expertise
24 through pilot projects such as EV Everywhere (see Section 9.2.4.1 of Schedule 2-5-4 -
25 Asset Management Process), where Hydro Ottawa has commissioned and is testing the
26 operations of two small-scale BESS facilities. Simultaneously, Hydro Ottawa will
27 leverage external expertise by partnering with specialized consulting firms, system
28 integrators, and equipment manufacturers for design, project management, and
29 advanced technical support, while also engaging with industry groups and academic

1 institutions to stay current on evolving technologies, codes, and best practices. The
2 OM&A costs associated with maintaining the BESS are shown in Table A.

3
4 ii) Hydro Ottawa has chosen utility-owned Battery Energy Storage Systems (BESS) to
5 meet its capacity needs in these areas due to the timing of the need and the limitations
6 of traditional infrastructure options. Refer to the response to parts (d) and (e) above for
7 the details of the justifications for the selection of the BESS in each region.

8
9 While customer-owned assets were considered, Hydro Ottawa determined that this
10 approach was not a viable immediate solution. Hydro Ottawa currently lacks the
11 necessary technological solutions and experience to manage the risks of
12 customer-owned BESS for capacity needs of this magnitude, and the time required to
13 build the capability and solutions to confidently depend on customer-owned assets for
14 peak capacity would jeopardize the reliability of the supply in these regions.

15
16 Despite this, Hydro Ottawa is committed to developing its expertise in this area. Through
17 the Non-Wires Customer Solutions Program, as outlined in Section 9.2.2.1 of Schedule
18 2-5-4 - Asset Management Process, and Alternative Energy Models, as outlined in
19 Section 9.2.4.4 of Schedule 2-5-4 - Asset Management Process, the utility is actively
20 working to enhance its ability to implement and manage a wider range of solutions in the
21 future.

22
23 g) Hydro Ottawa plans to leverage the learnings from its initial BESS deployments to improve
24 future projects by collecting and analyzing data and lessons learned throughout each project
25 phase. This includes examining everything from design, procurement, construction, and
26 commissioning to battery performance, operational efficiency, detailed costs, and safety
27 incidents. By doing so, Hydro Ottawa will refine its processes and update its standards,
28 guidelines, policies, and work methods for each subsequent deployment. These insights will be
29 codified into internal standard processes, ensuring consistency and efficiency across all future
30 battery projects, both those owned by Hydro Ottawa and those owned by customers. This

1 approach will allow Hydro Ottawa to optimize system designs, reduce project timelines, and
2 ensure safer, more reliable, and cost-efficient battery deployments, ultimately accelerating the
3 transition to a more resilient and sustainable grid. The four BESS capital assets will provide the
4 necessary data and experience to establish these best practices and build valuable internal
5 expertise.

6
7 h) The BESS installations will serve as a critical Non-Wires Solution to manage peak load by
8 charging during off-peak hours and discharging during periods of high demand or predicted
9 overloads, thereby addressing capacity constraints and enhancing local grid stability. This
10 approach is particularly valuable in areas with minor grid overloads where traditional wire
11 solutions are not immediately necessary or cost-effective (see Table C), providing direct control
12 and localized grid support to improve overall reliability, voltage performance, and system
13 resilience. Please refer to Section 2.3.2.3 of Schedule 2-5-8 - System Service Investments for
14 further details on how Hydro Ottawa intends to use each BESS system. Please refer to Table B
15 in part (c)(iv) above for energization timelines of each BESS system.

16
17 Additionally, Hydro Ottawa plans to assess the value of using the BESS for price arbitrage. For
18 more information refer to part (c) of the response to interrogatory 1-ED-6.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-112

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 8 (pdf Exhibit 2 part 4, p. 372)

Preamble:

With respect to Station Capacity Upgrades, Distribution Capacity Upgrades and Non-Wire Upgrades, Hydro Ottawa states that it expects “to add over 577MVA¹ in station capacity to Hydro Ottawa’s distribution system as a result of these projects, as compared to 160MVA over the previous period.”

QUESTION(S):

- a) What is the total weather normalized peak load growth forecast for Hydro Ottawa over the upcoming test period?
- b) Will the anticipated DER and BESS additions offset any of the forecast peak loads? Please discuss.

RESPONSE(S):

- a) Hydro Ottawa’s Attachment 2-5-4(F) - Decarbonization Study utilized a multi-scenario forecasts approach to capture different paces of decarbonization/ sensitivity analysis. Section 9.4.2.1 of Schedule 2-5-4 - Asset Management Process provides more information on the 5 different scenarios tested. The total system load growth forecast for these 5 different scenarios can be found in Figure 114 of Schedule 2-5-4 - Asset Management Process. In terms of peak load

1 growth for the 5 different scenarios, it ranges from 502 MVA (Low Sensitivity) to 1039 MVA
2 (Policy Guided) by 2030¹.

3 b) The anticipated DERs, BESS and Non-Wires Customer Solutions Program are expected to
4 offset forecasted peak loads; however, as stated in Section 2.1 of Schedule 9-2-1 - New
5 Deferral and Variance Accounts, the successful deployment of NWS programs is contingent
6 upon several external factors, including the pace of DER technology advancements, evolving
7 policies, and customer adoption rates. Due to the uncertainty around demand reduction
8 achievable through the new Non-Wires Customer Solutions Program, it has not been built
9 formally into the capacity assessment. In contrast, Hydro Ottawa has incorporated the expected
10 demand reductions achievable through the utility owned BESS projects, as these will be
11 available for dispatching by Hydro Ottawa during times of need. This reliable dispatch has been
12 captured as increased planned capacity as outlined in Section 2.3.2.3 of Schedule 2-5-8 -
13 System Service Investments and included within the 577MVA value shown on page 8 (and
14 footnote 1) of Schedule 2-5-8 - System Service Investments.

¹ Note that the values provided are depicted in Figure 114 in MW and have been converted to MVA to match units within the preamble

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-113**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 30 (pdf Exhibit 2 part 4, p. 394)

8
9 **Preamble:**

10 Figure 12 - Combined Forecast of stations: Carling TS, Lisgar TS, and Riverdale TS with Bronson
11 DS Conversion and NWSs, compares the IRRP Forecast, Planning Forecast, and the customer
12 load inquiries which are in the planning stages.

13
14 **QUESTION(S):**

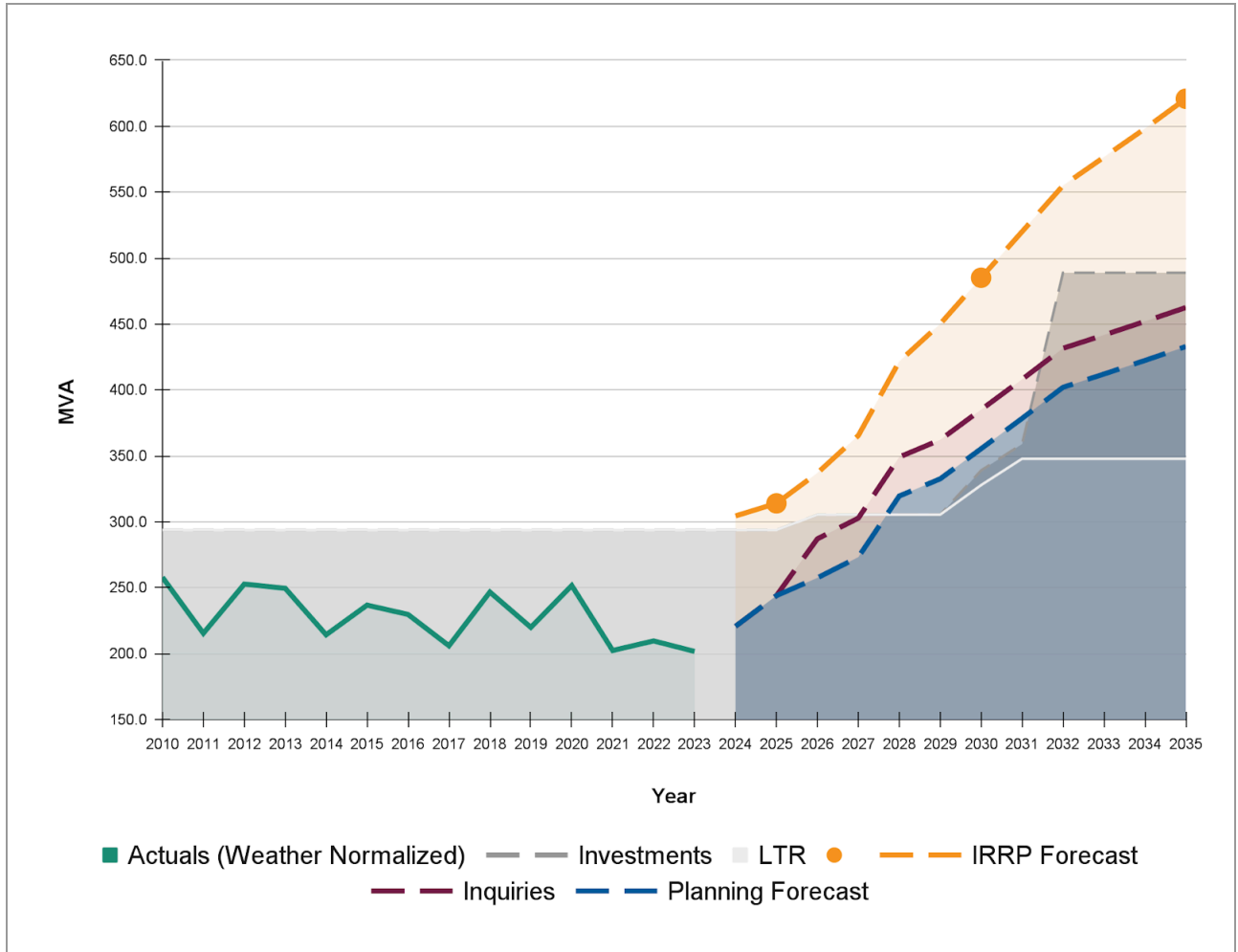
15
16 a) Please extend this Figure 12 to a 2010 start date.

17
18 **RESPONSE(S):**

19
20 See Figure A below:

1

Figure A: Extension of Figure 12 to 2010



2

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

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3 **2-Staff-114**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 49 (pdf Exhibit 2 part 4, p. 413)

8
9 Preamble:

10 Hydro Ottawa states, "The planned net expenditure under this program [Station Capacity Upgrades]
11 in the 2026-2030 period is \$192.2M."

12
13 **QUESTION(S):**

- 14
15 a) Does Hydro Ottawa expect this rate of new capacity additions to continue beyond the upcoming
16 test period? Please discuss.
17 b) Could any of the proposed Station Capacity Upgrades be deferred without causing significant
18 operational constraints? Please discuss.
19 c) If loads fail to grow as forecast in 2025, 2026, and 2027 could the decision be made as soon as
20 the lack of growth is identified to defer any of this proposed spending, or will it all be committed
21 immediately upon (or prior to) approval of the present application?
22

23
24 **RESPONSE(S):**

- 25
26 a) Hydro Ottawa expects the rate of new capacity additions to continue beyond 2030 (i.e. the
27 upcoming test period). Details of growth beyond 2030 has been discussed in Section 9.1.3 of
28 Schedule 2-5-4 - Asset Management Process.
29
30 b) None of the proposed Station Capacity Upgrades can be deferred without causing significant
31 operational constraints. The capacity upgrade expenditures are based on immediate needs of

1 the system focused on already constrained regions and areas with immediate, confirmed, and
2 committed load requirements necessary to meet customer service obligations. Please refer to
3 the response to interrogatory 2-Staff-108 for more details.

4

5 c) As explained in the response to interrogatory 2-Staff-108, investments related to capacity
6 upgrades are not directly linked to forecasted load growth in 2025, 2026 and 2027, but rather
7 based on immediate needs of the system focused on already constrained regions and areas
8 with immediate, confirmed, and committed load requirements necessary to meet customer
9 service obligations.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-115**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 52 (pdf Exhibit 2 part 4, p. 416)

8
9 **Preamble:**

10 Hydro Ottawa states that it is “proposing to add 24.5MW of capacity through Utility-Owned Battery
11 Energy Storage Solutions (Beckwith, Casselman, Bayshore/QCH and Core & West 13kV regions)
12 and 20 to 30MW additional capacity from Non-Wires Customer Solutions Program (Kanata North,
13 Core & West 13kV regions).”

14
15 **QUESTION(S):**

- 16
17 a) If any of the proposed BESS developments proves to have been sub-optimally located as new
18 DERs are added, is it economically feasible to relocate the BESS equipment to a better
19 location?
20 b) How will Hydro Ottawa evaluate the above business case?

21
22
23 **RESPONSE(S):**

24
25 a) Hydro Ottawa has not evaluated whether it is economically feasible to relocate the BESS
26 equipment to another location. The economic feasibility of relocating or canceling the BESS
27 project based on new information or opportunities will continue through all phases of the project
28 based on a cost, benefit and risk analysis.

- 1 b) Hydro Ottawa will continue to use the assessment criteria as defined in 9.2.1 of Schedule 2-5-4
- 2 - Asset Management Process when evaluating the business case for BESS projects and their
- 3 optimal location.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-116**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 72 (pdf Exhibit 2 part 4, p. 436)

8
9 **QUESTION(S):**

10
11 a) Hydro Ottawa states the following as a Grid modernization objective, “Strengthened Customer
12 Engagement & Empowerment: Engage and empower customers by providing them with
13 real-time data and tools to manage their energy use.” Please discuss if the customer tools that
14 will be implemented under this program are incremental to the customer tools that will be
15 implemented under the AMI 2.0 program?

16
17
18 **RESPONSE(S):**

19
20 a) To clarify, the Distribution System Observability program as indicated in Ref. 1. as well as the
21 introduction of AMI 2.0 within the Metering Renewal program described in Section 5 of Schedule
22 2-5-7 - System Renewal Investments do not implement customer tools.

23
24 Hydro Ottawa's Grid Modernization objective, "Strengthened Customer Engagement &
25 Empowerment: Engage and empower customers by providing them with real-time data and
26 tools to manage their energy use," is a broad outcome achieved through a combination of
27 strategic investments, rather than being solely driven by a single program.

28
29 As described on page 69-70 within Schedule 2-5-8 - System Service Investments, Distribution
30 System Observability, which is a Budget Program within Distribution Enhancements does not
31 implement customer tools, rather it enables real-time observability which is a requirement to

1 effectively deliver on a number of programs and services targeted to engage and empower
2 customers.

3
4 “Real-time observability is foundational for effective advanced flexible load management,
5 providing the essential data needed to dynamically balance grid demand. Investments in
6 advanced monitoring systems empower grid operators with the visibility to predict and respond
7 to load fluctuations, enhancing grid stability and resilience. By enabling precise, data-driven
8 control, observability optimizes the integration of distributed energy resources and facilitates
9 targeted demand response programs. Observability provides the data that allows for the
10 real-time reaction to grid conditions, a necessity to maintain grid stability while effectively
11 managing flexible loads.”¹

12
13 In addition to the above, increased observability is also an outcome of the Metering Renewal
14 program through introduction of AMI 2.0 as described in Section 5 of Schedule 2-5-7 - System
15 Renewal Investments. As with the Distribution System Observability program, the Metering
16 Renewal program and introduction of AMI 2.0 does not directly implement customer tools, it
17 increases grid observability, an example of which is providing customer outage data from the
18 meter.

19
20 The customer tools to manage energy use are largely an outcome of investments categorized
21 under Section 3 of Schedule 2-5-9 - General Plant. These investments contribute to the
22 development and deployment of customer-facing platforms to improve customer experience and
23 equip them to better navigate the complexities of the energy transition. As described on page 14
24 of Schedule 2-5-9 - General Plant, Hydro Ottawa intends to leverage data analytics and
25 behind-the-meter disaggregation to provide customers with granular data and tools to manage
26 their energy use. Hydro Ottawa will also use this data to inform planning, monitor the impacts of
27 electrification, and unlock new NWS opportunities.

¹ Section 3 Distribution Enhancements, Schedule 2-5-8 - System Service Investments, page 70.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-117**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 73 (pdf Exhibit 2 part 4, p. 437)

8
9 **Preamble:**

10 Hydro Ottawa states that the reliability driver for the Distribution Enhancement Program focuses on
11 Real-time Monitoring of Distribution Assets, and Enhanced Grid Resilience to Adverse Weather
12 Events, and System Reconfiguration to Optimize Outage Management and Load Restoration.

13
14 **QUESTION(S):**

15
16 a) Please discuss if, and how, the proposed investments would have reduced the impact of the
17 2022 Derecho by materially reducing the duration of customer outages and/or the number of
18 customers interrupted during and following the event. In your response, please provide the
19 specific reconfiguration options that would have been enabled by the investment.

20
21
22 **RESPONSE(S):**

23
24 a) Hydro Ottawa's proposed Distribution Enhancement Program, with its focus on enhanced grid
25 resilience and enhanced observability would have materially reduced the impact of the 2022
26 Derecho by lessening both the duration of customer outages and the number of customers
27 interrupted through the following means:

28
29 Distribution System Resilience:

30 As per the details on page 68-69 in Section 3 of Schedule 2-5-8 - System Service
31 Investments, the Distribution System Resilience Program's investments are designed to

1 directly mitigate the physical damage caused by severe weather events like the 2022
2 Derecho, which was characterized by high winds and falling trees. The following initiatives
3 would have reduced the initial number of outages and the extent of the damage, thereby
4 shortening restoration times:

- 5 ● Strategic Undergrounding: Direct investment in burying vulnerable sections of
6 overhead lines would have directly reduced damage from high winds and falling
7 trees, which were major contributors to the widespread outages during the Derecho.
8 This proactive measure minimizes the initial impact of such storms, leading to fewer
9 and shorter outages.
- 10 ● Storm Hardening: Reinforcement of existing overhead infrastructure, including
11 revised design standards for anti-cascading strategies and the use of composite
12 poles with storm guying, would have made the grid more robust against severe
13 weather. This reduces structural failures and prevents cascading outages.
- 14 ● Undergrounding of Station Egress Points and Line Relocation: Protecting critical
15 infrastructure coming out of substations by undergrounding feeders, or relocating
16 vulnerable lines to less exposed areas or easy access area, reduces their
17 susceptibility to damage, minimizing the need for extensive re-routing post-event and
18 enabling faster recovery of substations.
- 19 ● Feeder Reconfiguration and Addition of Feeder Ties: The investments enable the
20 optimization of feeder configurations and the addition of tie points. This builds
21 redundancy in the system and balances customer counts, allowing for the re-routing
22 of power around damaged sections and isolating faults more efficiently. This would
23 be critical for quickly restoring power to unaffected sections of the grid during a
24 widespread event like the Derecho.

25
26 **Distribution System Observability:**

27 In addition to hardening the grid through the Distribution System Resilience Program, the
28 following investments proposed by the Distribution System Observability Program on page
29 69-72 in Section 3 of Schedule 2-5-8 - System Service Investments would have enabled
30 advanced operational capabilities that would have been critical for managing the widespread
31 outages and accelerating restoration efforts during and after the Derecho:

- 1 ● Remote Operable Switches: Deployment of these devices provides real-time field
2 data with remote control capabilities. This would allow operators to remotely open
3 and close circuits to isolate faults and restore power to unaffected areas without
4 sending crews to the site, reducing outage duration during a large-scale event.
- 5 ● Advanced Monitoring Technologies: Smart Fault Current Indicators (FCIs) provide
6 advanced sensing and monitoring capabilities that allow for quicker identification of
7 fault locations during the Derecho, rather than relying on manual assessment.
- 8 ● Faster Fault Detection and Isolation: With real-time data, our System Operators
9 could more quickly and accurately identify outage locations and causes. This
10 capability reduces the time required for crews to locate faults, accelerating power
11 restoration.

12

13 Hydro Ottawa did not track the specific reconfigurations undertaken during its response to the
14 Derecho and therefore can not provide the options these actions would have enhanced;
15 however, these comprehensive investments, particularly in grid resilience and real-time
16 operational visibility and control, would have helped to minimize both the initial impact and the
17 subsequent restoration time for major disruptive events such as the 2022 Derecho, ensuring
18 safer and more reliable service for Hydro Ottawa customers.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

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3 **2-Staff-118**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 73 (pdf Exhibit 2 part 4, p. 437)

8
9 **QUESTION(S):**

10
11 a) Table 6 - Distribution Enhancement Program Performance Outcomes, highlights that improved
12 “grid control and observability through the installation of Smart FCIs and Smart Switches,” will
13 contribute to improved productivity and system performance. Will this improved productivity
14 result in reduced O&M costs? Please discuss.

15
16
17 **RESPONSE(S):**

18
19 a) The improved grid control and observability from Smart FCIs and Smart Switches are expected
20 to enhance productivity by reducing truck rolls, enabling faster outage detection and restoration,
21 and optimizing maintenance through data-driven decisions. While these efficiencies aim to
22 reduce certain O&M activities like manual operations and reactive repairs, they also necessitate
23 increased spending for expanded maintenance programs specifically for these new smart
24 devices. Therefore, despite the productivity gains, this initiative does not necessarily translate to
25 a net reduction in overall O&M costs, as the new maintenance requirements will offset the
26 savings.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

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3 **2-Staff-119**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 99 (pdf Exhibit 2 Part 4, p. 463)

8 Ref. 2: Exhibit 2 / Tab 5 / Schedule 2 / p. 17 (pdf Exhibit 2 Part 2, p. 136)

9
10 **Preamble:**

11 In its application, Hydro Ottawa mentions EV Everywhere and ODERA as NWS initiatives that focus
12 on DER integration and grid optimization while utility-owned BESS and NWCSP programs are
13 described as addressing system constraints to support existing system needs (e.g., supporting
14 existing capacity and strategic phasing of wire upgrades). Hydro Ottawa also refers to its “grid
15 modernization roadmap” when describing proposed NWS investments.

16
17 **QUESTION(S):**

18
19 a) Please elaborate on Hydro Ottawa’s “grid modernization roadmap” by identifying major
20 milestones and timelines Hydro Ottawa hopes to achieve over the next 5-10 years.

21 i) Please explain how each of the proposed NWSs, including NWCSP, BESS, ODERA,
22 and EV Everywhere, fits into Hydro Ottawa’s grid modernization roadmap.

23 b) Please clarify how Hydro Ottawa has considered the uncertainty regarding the pace of the
24 energy transition, adoption of DERs, and the regulatory policies associated with such matters in
25 its NWS strategy.

26 c) Please elaborate as to why the proposed NWS initiatives for which rate funding is requested
27 (including ODERA and EV Everywhere, if applicable) are reasonable and appropriate in terms
28 of costs and timelines.

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RESPONSE(S):

EV Everywhere, and ODERA are not NWS, but rather projects to support the implementation of technology platforms, capabilities, services, standards and rules that will enable Hydro Ottawa's ability to effectively integrate and manage DERs.

- a) Please refer to page 18 of attachment 2-Staff-57(A) - Hydro Ottawa Grid Modernization Strategy 2025 for the visualization of the roadmap as contained in the latest version of the strategy.

To advance Hydro Ottawa's Grid Modernization Strategy, a long term vision reaching beyond 2030, Hydro Ottawa has developed a Grid Modernization Roadmap. This roadmap outlines key milestones over the next five years in support of the five Grid Modernization Objectives: enhanced reliability, adaptive grid flexibility, fortified resilience and robust security, strengthened customer engagement and empowerment, and sustainable decarbonization and renewable integration. The key roadmap milestones are outlined below by portfolio.

Key Milestones (2025-2030):

- **Business & Strategy:** Hydro Ottawa will continuously review and update its Grid Modernization Strategy to align with evolving energy demands and customer needs, ensuring efficient project delivery. This will be supported by developing and maintaining Key Performance Indicators (KPIs) to track progress and inform strategic adjustments, alongside progressing Grid Modernization Governance for effective corporate oversight. (Ongoing-2030).
- **Data & Asset Management:** Hydro Ottawa will enhance asset management through technology integration of data and implementation of an Enterprise Asset Management (EAM) system (2025-2028). Hydro Ottawa will develop efficient processes and tools for hosting capacity assessment, increasing awareness and visibility of the distribution system's ability to accommodate new connection requests (Ongoing-2027).

- 1 ● **Physical Infrastructure:**
- 2 ○ Deploy AMI 2.0 technology (2026-2030).
- 3 ○ Deploy Battery Energy Storage Systems (BESS) at 4 key areas with grid constraints
- 4 (2026-2030).
- 5 ○ Increase observability by developing a system-wide strategy to deploy sensors on
- 6 the system (Ongoing-2027) including Smart Fault Current Indicators (Ongoing-2030)
- 7 and Station protection and control upgrades (Ongoing-2030).
- 8 ○ Increase grid controllability by installing remotely operable switches (Ongoing-2030).
- 9
- 10 ● **Communication:** Develop Field Area Network (FAN) strategies (2026-2030), with pilot
- 11 solutions implementation (2026-2028), leading to full implementation (2029-2030).
- 12 Additionally, the Optical Transport Network (OTN) will be expanded (2026-2030).
- 13
- 14 ● **Control & Optimization:** Continue Advanced Distribution Management System (ADMS)
- 15 implementation and advancements (2026-2030), continue with ODERA design and pilot
- 16 (Ongoing-2028), continue with DER pilots (Ongoing-2027) and EV impact assessment
- 17 (2026) to inform DER and DERMS strategies (2028) and subsequent DERMS
- 18 implementation (2029-2030).
- 19
- 20 i) It is important to clarify that Hydro Ottawa’s NWS investments (NWSCP and BESS)
- 21 are enabled by the activities undertaken as part of the Grid Modernization Roadmap
- 22 and not actually elements of the Grid Modernization Roadmap itself. EV Everywhere,
- 23 as described by the IESO is a pilot that “will use AI to create an online service for EV
- 24 owners that will pool the storage and charging capabilities of EV batteries to smooth
- 25 out demand peaks and take advantage of lower cost energy at off-peak. The
- 26 automated system will also gauge customer interest and impacts.”¹ ODERA is a key
- 27 element of the roadmap as it enables the foundational technology elements
- 28 necessary for employing flexible resources within NWSCP, namely load forecasting

¹<https://ieso.ca/en/Corporate-IESO/Media/News-Releases/2022/04/Artificial-Intelligence-Pilot-to-Support-EV-Electricity-Demand-in-Ottawa>

1 and DER management and dispatch. Additional details of each of the items listed
2 above are provided below:

- 3
- 4 ● **Non-Wires Customer Solutions Program (NWCSP):** This program leverages energy
5 efficiency, generation, DERs and demand response initiatives through customer participation
6 by offering incentives. The NWCSP will unlock short-term capacity in targeted areas, reduce
7 peak demand, and empower customers to manage energy use, thereby enhancing
8 reliability, grid flexibility, and customer engagement. The program launches within the
9 2026-2030 rate period, with initial deployment in Kanata North. Note that NWCSP is not
10 tracked within the Grid Modernization Roadmap as the initiative is monitored through the
11 Customer Experience Strategy. Further information on Hydro Ottawa's Non-Wires Customer
12 Solutions Program can be found on page 276 in Section 9.2.2.1 of Schedule 2-5-4 - Asset
13 Management Process and in the response to interrogatory 2-Staff-67.
 - 14
 - 15 ● **Battery Energy Storage Systems (BESS):** Over the course of 2026-2030 Hydro Ottawa
16 plans to install utility-owned BESS in 4 constrained regions: West 28kV (Beckwith), Bells
17 Corners/Bayshore 8kV (Bayshore), Casselman 8kV (Casselmann) and Core/West 13kV (King
18 Edward TS). These BESS will be utilized to manage peak load, support growth, and
19 enhance grid resilience, reliability, and optimization through direct control and localized grid
20 support. Hydro Ottawa aims to install 24.5 MW of BESS capacity across the 4 regions.
21 Within the Grid Modernization Roadmap, the BESS initiatives are tracked under the Physical
22 Infrastructure Portfolio, within their own workstream. Refer to Section 9.2.2.2 of Schedule
23 2-5-4 - Asset Management Process, Section 2.3.2.3 in Schedule 2-5-8 - System Service
24 Investments and Hydro Ottawa's response to interrogatory 2-Staff-111 for further information
25 on the BESS projects.
 - 26
 - 27 ● **Ottawa Distributed Energy Resource Accelerator (ODERA) Project:** The ODERA project
28 is not considered a NWS. The project will advance Hydro Ottawa's grid modernization
29 strategy by leveraging advanced technology to address grid constraints and system
30 reliability challenges. Within the Grid Modernization Roadmap, ODERA is tracked under the
31 Control and Optimization Portfolio within the DERMS workstream. Refer to Section 3.6.3.1

1 of Schedule 2-5-8 - System Service Investments for further information on the ODERA
2 project, as well as the response to interrogatory 2-Staff-69.

- 3
- 4 ● **EV Everywhere Pilot:** Hydro Ottawa's collaboration with BluWave-ai on the EV Everywhere
5 project integrates customer devices like EV chargers and battery storage for demand
6 response. With planned completion in 2025, this pilot supports grid modernization by
7 exploring scalable NWS options for load management from widespread EV adoption and
8 other electrified technologies, adapting the grid to increasing electrification. Within the Grid
9 Modernization Roadmap, EV Everywhere is reported under the Control and Optimization
10 Portfolio, specifically under the DERMS workstream, under the heading of DER Pilots.
11 Refer to Section 9.2.4.1 in Schedule 2-5-4 - Asset Management Process for more
12 information on the EV Everywhere pilot and the response to interrogatory 2-Staff-68.

- 13
- 14 b) Hydro Ottawa has addressed the uncertainties surrounding the energy transition, DER adoption,
15 and associated regulatory policies through a variety of strategies including the use of proposed
16 deferral and variance accounts.

17

18 **Pace of Energy Transition**

19 As outlined in Section 9.4 of Schedule 2-5-4 - Asset Management Process, Hydro Ottawa has
20 refined the planning forecasting practices by employing two distinct approaches: near-term
21 Planning Forecast and medium-to-long-term IRRP Forecast. The Planning Forecast assesses
22 near-term needs at the station level, incorporating planned developments, known large load
23 requests, and initial-phase customer requests. The IRRP Forecast leverages hourly system
24 coincident peak forecasts from the Decarbonization Study's Reference Scenario. This provides
25 a vision of medium-to-long-term system needs, guided by policy directives.

26

27 This dual approach allows Hydro Ottawa to integrate the long-term uncertainties of the energy
28 transition while simultaneously grounding the needs in current service territory trends.

1 **Adoption of DERs**

2 Hydro Ottawa manages the uncertainty of DER adoption through a multi-pronged strategy
3 focused on customer engagement, grid modernization, and flexible NWS.

4
5 As described in Section 2.2 of Schedule 1-4-1 - Customer Engagement Ongoing, Hydro Ottawa
6 actively educates customers through diverse channels like its thinkenergy podcast, social
7 media, and newsletters to overcome DER adoption barriers. In Section 2.4 of that same
8 schedule, there is more detail about how Hydro Ottawa connects customers to provincial and
9 federal programs that incentivize DER technologies, such as the Save on Energy Retrofit
10 Program. By supporting these programs, Hydro Ottawa helps create a more predictable
11 environment for DER growth. For a fulsome overview of the work Hydro Ottawa is undertaking
12 to promote and enable increased deployment and integration of DERs, please see Hydro
13 Ottawa's response to interrogatory 1-PP-7 part (e).

14
15 To prepare the grid, Hydro Ottawa is investing in advanced technology solutions like ADMS,
16 DERMS and AMI 2.0 to enable two-way power flow and manage the complexity of increasing
17 DERs.

18
19 Hydro Ottawa is also directly addressing adoption uncertainty by launching the Non-Wires
20 Customer Solutions Program, to encourage adoption and utilize customer-owned DERs to
21 address specific system constraints as a resource for grid management.

22
23 **Regulatory Policies**

24 To address regulatory uncertainties and the OEB's evolving Benefit-Cost Analysis Framework
25 and DSO consultation, Hydro Ottawa has proposed a symmetrical NWS variance account. This
26 account will manage differences between forecasted and actual NWS operational costs,
27 providing crucial funding flexibility to adapt to changes in DER uptake and government policies
28 outside of Hydro Ottawa's direct control. Please refer to part (a) of Hydro Ottawa's response to
29 interrogatory 1-Staff-18, and Section 2.1 of Schedule 9-2-1 - New Deferral and Variance
30 Accounts for additional information.

1 c) Hydro Ottawa's Non-Wires Customer Solutions Program (NWCSP) and Battery Energy Storage
2 Systems (BESS) are driven by specific and immediate system capacity needs, as outlined in
3 Sections 9.1 and 9.2 of Schedule 2-5-4 - Asset Management Process.

4
5 The Benefit-Cost Analysis completed for the proposed NWCSP portfolio within the Kanata North
6 region indicates a positive Net-Present-Value. Further details regarding the NWCSP
7 investments are located in the response to interrogatory 2-Staff-67. Similarly, further details for
8 BESS investments can be found within the response to interrogatory 2-Staff-111.

9
10 The ODERA project is not a proposed NWS. Rather, the project is an innovation initiative
11 designed to explore and adapt technological solutions that will support Hydro Ottawa's grid
12 modernization strategy. For more information regarding the ODERA project, including its
13 objectives and anticipated benefits, please refer to interrogatory response 2-Staff-69.

14
15 There is no rate funding requested for the EV Everywhere project. Please refer to response to
16 interrogatory 2-Staff-68 for further details.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-120**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / Attachment A / pp. 5-6 (pdf Exhibit 2 part 4, pp. 525-526)

8
9 **QUESTION(S):**

10
11 a) Hydro Ottawa states, “The goal of this effort is to capture an option for future HOL use that will
12 fit within an appropriate budget. It is recognized that there is a specific focus on providing a FAN
13 [Field Area Network] solution to support HOL’s 2024 rate case submission. The ultimate
14 decision may be based on additional information obtained in future design iterations and vendor
15 negotiations.”Does the budget for FAN given in the DSP assume a specific solution based upon
16 the "ultimate decision" noted in this statement having been made, or is the budget a
17 placeholder, the actual costs of which will be determined after that ultimate decision has been
18 made? Please discuss.

19 b) Hydro Ottawa states, “The next step is to implement a FAN to enable reliable communications
20 to grid devices not directly connected to HOL’s fibre infrastructure to support current and future
21 applications including but not limited to Smart Grid, Distributed Energy Resources, and next
22 generation AMI.” This statement appears to treat the development of the FAN as a foregone
23 conclusion ("the next step"), to make full use of Hydro Ottawa's existing fiber LAN. Please
24 provide any benefits/cost analysis that has been undertaken to demonstrate the necessity of
25 this investment.

26
27
28 **RESPONSE(S):**

29
30 a) The budget for FAN in the DSP is not based on a specific solution with a finalized vendor or
31 core type for Hydro Ottawa's pilot needs. Instead, it is a budget placeholder. The Wireless

1 Technology Study (Attachment 2-5-8(A) - Wireless Technology Study) provided budgetary
2 estimates for various Private LTE (PLTE) options across different frequencies, such as 900
3 MHz, 1800 MHz, and 3900-3980 MHz. These were general cost estimates, not tied to a
4 particular vendor or specific core architecture for Hydro Ottawa's pilot requirements.

5
6 The scale of the FAN budget in the DSP is significantly smaller than the overall network costs
7 estimated for covering the entire Ottawa region. This DSP budget specifically allocates funds for
8 a PLTE pilot project, which includes deploying a single pilot site and an Evolved Packet Core for
9 lab testing. This pilot is intended as a proof-of-concept to evaluate PLTE's performance for
10 various applications. It will also involve testing different configurations using public carrier
11 options alongside the PLTE pilot to compare their respective results and suitability for Hydro
12 Ottawa's requirements. The ultimate decision regarding the FAN solution for future use will be
13 made based on the results of this pilot with further design iterations and vendor negotiations
14 prior to next rate application.

15
16 b) The critical assets within most substations are already monitored by fiber, which offers the
17 highest reliability. The next investment is crucial to extend and improve the connectivity and
18 reliability of the field area devices, as the current Field Area Network (FAN) technology has
19 drawbacks in achieving the required reliability as mentioned in Section 2.2.1 of Attachment
20 2-5-8(A) - Wireless Technology. The necessity and reasons for this investment in the FAN are
21 further detailed in the response to interrogatory 2-Staff-107.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-121**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 106 (pdf Exhibit 2 part 4, p. 470)

8
9 **QUESTION(S):**

10
11 a) Table 11 - Performance Targets for the Station Enhancement Program explains how online
12 station transformer monitoring will help contribute to proactive management of station
13 transformers and improve real-time condition information. Please explain whether the new
14 monitoring will enable extended manual inspection cycles and reduced O&M costs.

15
16
17 **RESPONSE(S):**

18
19 a) The impact of the online station transformer monitoring on manual inspection cycles and O&M
20 costs is detailed below:

21
22 **Manual Inspection Cycles:** Hydro Ottawa currently performs a manual inspection of all station
23 assets (including station transformers) to identify issues or deficiencies. Each station is
24 inspected at least once every three months. The new monitoring systems and overall strategy
25 do not extend manual inspection cycles for stations. Instead, the information collected from
26 these devices is used to enhance Testing, Inspection, and Maintenance programs by leveraging
27 more detailed and accurate condition data, leading to proactive and condition-based
28 maintenance. This approach allows for a better understanding of station transformer condition
29 and targeted interventions, rather than simply extending existing manual cycles.

1 **O&M Costs:** The new monitoring systems are not expected to reduce overall O&M costs for
2 station programs. The intended purpose of online station transformer monitoring is to proactively
3 identify potential faults, thereby improving asset observability and reliability by reducing
4 unexpected failures. The data obtained through online monitoring will be utilized for near
5 real-time station transformer management, complementing static offline data obtained through
6 annual maintenance. Online monitoring data is useful for identifying potential electrical and
7 thermal faults as the transformer's condition worsens, but before an actual fault occurs, as
8 outlined in Section 4.3.2 Current Issues under Schedule 2-5-8: System Service Investments.
9 This allows Hydro Ottawa to remove the transformer from service and plan maintenance
10 strategies accordingly, thereby avoiding potential unplanned emergency replacement costs and
11 customer disruptions.

12
13 The primary benefit highlighted is the ability to enable proactive management of station
14 transformers and improve real-time condition information. This helps to identify faults earlier and
15 supports planned renewal projects, thereby avoiding disruptive unplanned transformer renewal
16 projects that would divert resources from other work. While this shifts costs from reactive,
17 high-cost emergency work to more managed, proactive spending, it does not translate to a net
18 reduction in O&M costs for stations programs, which are increasing due to enhanced
19 maintenance and testing.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **2-Staff-122**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 9 / pp. 64-74 (pdf Exhibit 2 part 4, pp. 642-652)

8
9 **Preamble:**

10 Hydro Ottawa has forecast CCRA Program Expenditures for 2026 through 2030 to be \$45.9M and
11 lists new and ongoing projects for which Hydro Ottawa will be required to make a contribution.

12
13 **QUESTION(S):**

14
15 a) For each forecast cost owing or credited to Hydro One over 2026-2030:

- 16 i) Please categorize the costs as construction costs or load true-up.
17 ii) Please provide the agreements between Hydro Ottawa and Hydro One.
18 iii) Please provide any estimates and calculations from Hydro One (i.e. output of the Hydro
19 One DCF model). In the absence of estimates from Hydro One, please provide Hydro
20 Ottawa's detailed calculations of the true-up amount.
21 iv) In cases where Hydro Ottawa forecasts a payment during 2026-2030 due to reduced or
22 unrealized load, please explain why the load forecast at the time of the agreement with
23 Hydro One was not realized.

24
25
26 **RESPONSE(S):**

27
28 a)

- 29 i) For the 2026-2030 all costs are categorized as construction costs, there are no load
30 true-ups forecasted for the 2026-2030 period. Please refer to part (iv) below for
31 additional details.

1 ii) See Table A below for the list of proposed projects and the corresponding CCRA stage
 2 along with a reference to the agreements between Hydro Ottawa and Hydro One that
 3 are attached to this interrogatory response.¹
 4

5 Note that all projects in the Upcoming Connection Cost Estimate stage do not yet have an
 6 agreement.
 7

8 **Table A – Hydro One CCRA Projects, Stages and Agreement Reference**

Proposed Project	CCRA Stage	Attachment Reference
Mer Bleue TS	Connection Cost Estimate	Attachment 2-Staff-122(A) - Executed Mer Bleue CCRA - REDACTED
Russell TS transformer replacement	Initial CCRA	Attachment 2-Staff-122(B) - Executed Russell TS CCRA - REDACTED
Hydro Road TS	Connection Cost Estimate	Attachment 2-Staff-122(C) - Executed Hydro Road CCRA - REDACTED
Cyrville station upgrade	Feasibility Study Agreement	Attachment 2-Staff-122(D) - Executed Cyrville Feasibility Study Agreement - REDACTED
Greenbank TS	Upcoming Connection Cost Estimate	
New Kanata North TS	Upcoming Connection Cost Estimate	
Carling TS secondary cable upgrade	Upcoming Connection Cost Estimate	
Lisgar TS secondary cable upgrade	Upcoming Connection Cost Estimate	
King Edward secondary cable upgrade	Upcoming Connection Cost Estimate	
Russell TB Switchgear Renewal	Upcoming Connection Cost Estimate	
Hinchey TH Switchgear Renewal	Upcoming Connection Cost Estimate	
New Bronson 13kV	Upcoming Connection Cost Estimate	

9
 10 iii) There are no DCF models available from Hydro One at this time as all the projects are
 11 currently in the preliminary Feasibility Study, Connection Cost Estimate or Initial CCRA
 12 stage.

¹ Please note that confidential and non-relevant information has been redacted in certain CCRA agreements. The rationale for these redactions is outlined in Hydro Ottawa's confidentiality submission.

1 iv) No forecast load true-up payments are expected for projects from 2026 to 2030 due to
2 reduced or unrealized load. Although seven CCRA's are slated for Load True-ups during
3 this period, as listed below, no payments have been forecasted due to anticipated
4 growth in those regions. For more details on forecasted growth in these regions, please
5 refer to Section 9 of Schedule 2-5-4 - Asset Management Process. The seven CCRA's
6 due for Load True-ups are:

7

8

1. Limebank MTS T4 Upgrade (2026)

9

2. Ellwood Station CCRA (2026)

10

3. Cambrian MTS & S7M Line Upgrade (2027)

11

4. King Edward Transformer Upgrade (2027)

12

5. Slater T2 & T3 Upgrade (2029)

13

6. Orleans TS Feeder CCRA (2029)

14

7. A6R Upgrade HONI (2029)

Connection Cost Estimate Agreement – (Mer-Bleue MTS)

Hydro Ottawa Limited (the "**Customer**") has requested and Hydro One Networks Inc. ("**Hydro One**") has agreed to perform the Work as defined in the Scope of Work attached hereto (as Schedule "A"), to determine the estimated cost of the Proposed Project (defined below) and to undertake the Work under the Standard Study Agreement Terms and Conditions v. 5 (November 2011) attached hereto as Schedule "B", Schedule "A" and Schedule "B" both forming a part hereof (the "**Agreement**").

I. Proposed Project

The Customer is proposing to connect a 230kV/27.6kV transformer station, Mer-Bleue MTS, (the "**Customer's Facilities**") to Hydro One's transmission system on 230kV circuits D5A and A25S, approximately [REDACTED] from Hydro One's Hawthorne TS (the "**Proposed Project**").

II. Information Requirements

The Customer shall provide Hydro One with the following:

1. site location map(s) with suitable details of the major equipment location (including transformer, line entrance structure, 230kV breakers), line routing and the proposed connection to Hydro One's facilities;
2. single line diagrams of the transformer station, including all major 230kV and 27.6kV equipment;
3. technical descriptions of the operating philosophy of the electrical equipment, and the protection and control philosophy of the Customer's Facilities (including any proposed Customer Facilities related to the Proposed Project) that could affect Hydro One's transmission system; and
4. where applicable, a completed Impact Assessment Application for a System Impact Assessment to be performed by the IESO (available at www.ieso.ca) and a completed application for a Customer Impact Assessment to be performed by Hydro One.

III. Completion Date:

Hydro One shall complete the Work by no later than nine(9) months following the latest of:

- (a) the Customer executing this Agreement;
- (b) the Customer providing the information described above under the heading "Information Requirements";
- (c) where applicable, where the Customer has applied for a System Impact Assessment ("**SIA**") to be performed by the IESO, the Customer providing Hydro One with a copy of the SIA for the Proposed Project **OR** where Hydro One has applied for a SIA, Hydro One receiving the results of the SIA from the IESO; and
- (d) the Customer paying Hydro One the amount specified below in subsection V(a) under the heading "Costs".

IV. Impact of Subsequent Changes to the Information Provided by Customer or to the System Impact Assessment

If:

- (a) the Customer makes any changes to the information provided by the Customer as described above under the heading “Information Requirements” after Hydro One has commenced the Work; or
- (b) where applicable, the IESO makes any changes to the System Impact Assessment (“SIA”) for the Project;

and any of the changes in (a) or (b) above:

- (i) results in an increase in the cost of Hydro One performing the Work, then, notwithstanding the payments contemplated below under the heading “Costs”, the Customer shall make such further payment(s) as may be required by Hydro One in the time specified by Hydro One; and
- (ii) otherwise affects any other provision of this Agreement, including (but not limited to) the time required for completion of the Work, the parties shall negotiate and agree upon the required amendments to this Agreement, and Hydro One shall be under no obligation to resume performance of the Work until such time as the parties agree in writing on such amendments.

V. Costs

- (a) The Customer shall pay Hydro One’s Actual Cost of performing the Work. Hydro One estimates that the Actual Cost of performing the Work will be \$600,000 plus HST in the amount of \$78,000 which amount (including HST) the Customer shall pay Hydro One on the execution of this Agreement by the Customer (the “**Advance Payment**”). Hydro One shall apply the Advance Payment towards the Actual Cost of performing the Work.
- (b) Within 90 days after the completion of the Work, Hydro One shall provide the Customer with a final invoice or credit memorandum showing whether the Advance Payment exceeds or is less than the Actual Cost of performing the Work. Within 30 days after the said final invoice or credit memorandum is rendered by Hydro One, any difference between the Actual Cost (plus applicable Taxes) and Advance Payment shall be paid by Hydro One to the Customer (if the Advance Payment exceeds the Actual Cost plus applicable Taxes), or by the Customer to Hydro One (if the Advance Payment is less than the Actual Cost plus applicable Taxes).

VI. HST Registration Information

The HST registration number for Hydro One is [REDACTED]. The HST registration number for the Customer is [REDACTED].

VII. No Commitment to Back Feed and Ready for Service Dates for the Proposed Project Until CCRA Execution

The Customer acknowledges and agrees that Hydro One cannot agree to be bound to a ready for service date or a back feed date for the Proposed Project until such time as Hydro One and the Customer have executed a Connection and Cost Recovery Agreement (CCRA) for the Proposed Project.

VIII. Purchase Order

This Agreement will supersede the terms of any purchase orders issued by the Customer to Hydro One in respect of the Project irrespective of whether same have been issued by the Customer and/or accepted by Hydro One on or after the execution of this Agreement by the Customer.



IX. Term

Except as expressly set out in this Agreement, this Agreement shall be in full force and effect and binding on the parties upon the date that this Agreement was executed by Hydro One and shall expire on the date that is after the latest of:

- (a) Hydro One performing all of the Work; and
- (b) the Customer paying all amounts required to be paid by the Customer under the terms of this Agreement.

Termination of this Agreement for any reason shall not affect the liabilities of either party that were incurred or arose under this Agreement prior to the time of termination. Termination of this Agreement for any reason shall be without prejudice to the right of the terminating Party to pursue all legal and equitable remedies that may be available to it including, but not limited to, injunctive relief.

X. Counterparts

This Agreement may be executed by the parties in writing or via electronic signatures and in one or more counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be delivered via fax, electronic mail (in portable document format) or other transmission method and any counterpart so delivered is deemed to have been duly and validly delivered and be valid and effective for all purposes.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the Execution Date written below.

HYDRO ONE NETWORKS INC.

Signed by:

Robert Reinmuller

24DC60888B73411...

Name: Robert Reinmuller, P.Eng.

Title: Vice President, Transmission System Planning & Large Customer

Execution Date: January 16, 2025

I have the authority to bind the Corporation

HYDRO OTTAWA LIMITED

DocuSigned by:

Laurie Heuff

7E31070D87DA4EF...

Name: Laurie Heuff

Title: Vice President, Distribution System Planning and Asset Management

2024-12-12

DocuSigned by:

Steve Hawthorne

3FEDCAB67014DC

Name: Steve Hawthorne

Title: Director, Distribution Program Delivery

Date: 2024-12-12

I/We have the authority to bind the Corporation

SCHEDULE “A”: Scope of Work - Connection Estimates

Hydro One will work with the Customer to develop planning specifications for Hydro One’s use in preparation for developing estimates for the Proposed Project (“**Planning Specifications**”). The Planning Specifications may also identify the work that Hydro One requires the Customer to perform in respect of the Proposed Project.

Hydro One will prepare and provide the Customer with an estimate consistent with the Association for the Advancement of Cost Engineering (“**AACE**”)’s Class 3 accuracy in the range of +30%/-20% for the work that will be outlined in the Planning Specifications as work that is to be performed by Hydro One (the “**Estimate**”). For greater certainty, the Estimate:

- will include the cost and the required work plan and schedule for Hydro One to perform the work necessary in respect of the Proposed Project, including, but not limited to:
 - Installation of a line tap from circuit D5A and a line tap from circuit A25S.
 - Installation of wavetraps for circuit D5A.
 - Review and modification of protection and control settings for D5A and A25S at their terminal stations including the following (refer to the Protection Impact Assessment provided to IESO for the SIA):
 - Implement transfer trip sent from Hawthorne TS to Mer-Bleue MTS (including cascading transfer trip from St Isidore TS to Hawthorne TS).
 - Implement receiving of breaker fail redundant transfer trip (A and B) at Hawthorne TS sent from Mer-Bleue MTS, and cascade to other stations connected to the circuits (D5A: St Isidore TS, Orleans TS, Masson CGS, Longueuil TS; A25S: trip locally).
 - Coordinate with Customer for line back-up function at Mer-Bleue MTS 230kV side.
 - Review if blocking signal from Mer-Bleue MTS is required. Add blocking signal receive into protection logic if required.
 - At Hawthorne TS, install Main and Alt CTM equipment compatible with Customer’s teleprotection equipment and fiber medium.
 - Coordinate a suitable fiber demarcation point along the station fence at Hawthorne TS. Install splice box at demarcation point to transition between the Customer and Hydro One fiber. Review if the fiber installation completed as part of the Piperville MTS connection project can be used.
- will include real estate requirements and potential impact on land owners, environmental assessments and approvals, and regulatory approvals.
- will not include any estimate of the cost of the work that Hydro One identifies in the Planning Specifications as work that Customer must perform in respect of the Proposed Project.
 - Customer will build and own the station.
 - Customer is responsible to obtain all permits required for the station.
 - Refer to Protection Impact Assessment provided to IESO for SIA for protection and control requirements. The below provides high level requirements:
 - Implement transfer trip received from D5A and A25S TT (A and B), sent from Hawthorne TS and trip into the associated 230kV circuit breaker, then open disconnect switch.

- Install Breaker Fail (BF) protection on the 230kV circuit breakers. BF protection should send redundant (A and B) TT to Hydro One's Hawthorne TS.
- Redundant (A and B) line back-up function (for phase and ground protection) should be provided at the 230kV side of the transformers (each, respectively).
- Coordinate with Hydro One and if blocking signal is required as outlined in Hydro One scope of work above, implement blocking signal.
- Provide redundant fiber links for 'A' and 'B' teleprotection channels to Hawthorne TS (to splice box at Hawthorne TS as outlined in Hydro One work above). Path diversity is not required for the new teleprotection channels between Hawthorne TS and Mer-Bleue MTS. Coordination with Piperville MTS connection project possible. A and B teleprotection channels should be provided for D5A and A25S.
- The Customer's Mer-Bleue MTS shall communicate to Hydro One's ISOC via the Customer's existing ICCP link.

The schedule for performing the work outlined in the specifications will assume that the parties will enter into a CCRA by no later than the date that will be specified in the estimate. If the CCRA is not executed by such date, the required work plan, schedule and cost estimate will require revision.

The abovementioned activities, to be performed by Hydro One, shall be herein referred to as "**Work**".

At the request of the Customer, this Agreement is being executed and Hydro One is commencing to perform the Work in advance of the SIA being performed by the IESO and in advance of Hydro One performing a Customer Impact Assessment ("**CIA**") which Hydro One normally commences after the IESO has performed the SIA for the Proposed Project. The CIA and the SIA must be performed for the Proposed Project under the Transmission System Code. As such, the Customer is assuming that any additional requirements identified by the IESO in the SIA and/or in the CIA reports will not be included in the Estimate and all or a portion of same may need to be re-performed by Hydro One at the Customer's expense.

SCHEDULE B – Standard Study Agreement Terms and Conditions**1. Definitions**

In the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

“Actual Cost” means Hydro One’s charge for equipment, labour and materials at Hydro One’s standard rates plus Hydro One’s standard overheads and interest thereon.

“Applicable Laws” means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission, board, court or agency.

“Business Day” means a day that is not a Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto are not open for business during normal banking hours.

“Code” or “Transmission System Code” means the *Transmission System Code*, the code of standards and requirements originally issued by the OEB on July 14, 2000 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

“Confidential Information” has the meaning ascribed thereto in the Connection Agreement.

“Connection Agreement” means the form of connection agreement appended to the Transmission System Code as Appendix 1, Version A where the Customer is a load customer and Version B where the Customer is a generator (as that term is defined in the Transmission System Code). Notwithstanding the foregoing, if the Customer has a transmission connection agreement that has been modified in the manner described in Section 2 of Schedule 2 of Hydro One’s OEB-issued transmission licence ET-2003-0035 (the **“Hydro One Licence”**) to reflect the amendments described in Schedule 3 [for legacy system configurations as well as operating concerns for Bruce Power and OPG generation facilities] and/or Schedule 4 [to facilitate compliance with Power Reactor Operating Licences, issued by the Canadian Nuclear Safety Commission] of Hydro One’s transmission licence ET-2003-0035; or has entered in the transmission connection agreement described in Section 3 of Schedule 2 of Hydro One’s licence, any reference to Connection Agreement in this Agreement shall mean the Customer’s executed transmission connection agreement with Hydro One.

“Customer’s Facilities” has the meaning set forth in the *Code*, and includes, but is not limited to any new, modified or replaced Customer’s Facilities.

“IESO” means the Independent Electricity System Operator.

“Good Utility Practice” has the meaning set forth in the *Code*.

“Lender” means a bank or other entity whose principal business is that of a financial institution.

“OEB” means the Ontario Energy Board.

“OEB-Approved Connection Procedures” means Hydro One’s connection procedures as approved by the OEB from time to time.

“Person” shall include individuals, trusts, partnerships, firms and corporation or any other legal entity.

“Representative” means (i) a person controlling or controlled by or under common control of a party and each of the respective directors, officers, employees and independent contractors of a party and such party’s Representative, (ii) any consultants, agents or legal, financial or professional advisors of a party or such party’s Representative and (iii) in the case of Customer, any institution providing or considering providing financing for the Proposed Project, including such institution’s directors, officers, employees and independent contractors or its consultants, agents or legal, financial or professional advisors.

“Taxes” means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than Taxes imposed upon income, payroll or capital).

“Work” means the work to be conducted in accordance with the Scope of Work attached to the Agreement as Schedule “A”.

2. Representations and Warranties

Each party represents and warrants to the other that:

- (a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
- (b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
- (c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or

other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any material contracts or instruments to which it is bound; or any laws applicable to it;

- (d) any individual executing the Agreement, and any document in connection herewith, on its' behalf has been duly authorized by it to execute the Agreement and has the full power and authority to bind it;
- (e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
- (f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada); and
- (g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

3. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and in compliance with all Applicable Laws.

4. Except as provided herein, Hydro One makes no representation or warranty, express, implied, statutory or otherwise, including, but not limited to, any representation or warranty as to the merchantability or fitness of the Work or any part thereof for a particular purpose.

5. Customer Covenants

The Customer acknowledges and agrees that:

- (a) Hydro One has informed the Customer that the OEB-Approved Connection Procedures apply to the Proposed Project;
- (b) Hydro One has informed the Customer that should the Proposed Project proceed, an agreement must be executed by the Customer and Hydro One to address the terms and conditions (which may include terms with respect to capital contributions required to be made) of Hydro One performing the work required in order to provide for the connection of the Customer's Facilities prior to Hydro One initiating any modifications to Hydro One's facilities or purchasing any equipment;
- (c) the Customer will be responsible for ensuring that the Proposed Project complies with all Applicable Laws;

(d) if the Customer is a Generator Customer (as that term is defined in the *Code*), the Customer is responsible for:

- i. providing the IESO with the modeling and studies to show the acceptable dynamic behavior of the generators as specified in the IESO System Impact Assessment; and
- ii. any resulting requirements that come from the IESO's review of dynamic studies that were or are not part of the IESO's System Impact Assessment including, but not limited to changes required to be made to the Work as a consequence of such review;

(e) the Customer shall obtain all applicable approvals required by the IESO for the connection of the Proposed Project;

(f) all right, title and interest, including copyright ownership, to all information and material of any kind whatsoever (including, but not limited to the work product developed as part of the Work) that may be developed, conceived and/or produced by Hydro One during the performance of the Agreement is the property of Hydro One, and the Customer shall not do any act that may compromise or diminish Hydro One's interest as aforesaid;

(g) if the Work involves Hydro One preparing a Customer Impact Assessment, the Customer consents, notwithstanding any term to the contrary in the Agreement, to Hydro One releasing the completed Customer Impact Assessment Report to be prepared by Hydro One to the IESO, the Ontario Electrical Safety Authority and customers connected to Hydro One's transmission system in the vicinity of the Proposed Project that may be affected by the Proposed Project;

(h) if the Work involves Hydro One preparing a Customer Impact Assessment, it may provide a deposit to the IESO for the IESO studies in relation to the Proposed Project. In the event that the IESO refunds part of the deposit to Hydro One, Hydro One will refund such funds to the Customer within 30 days of receipt by Hydro One. In the event that the IESO studies cost more than the deposit, the Customer agrees that it will pay the additional costs of such studies as invoiced to Hydro One by the IESO; and

(i) Hydro One performs the Work based on the known and anticipated system conditions at the time the Work is performed, should there be any changes to system conditions, including, anticipated system conditions, between the time

that Hydro One completes the Work and when the Customer proposes to connect the Proposed Project, the Work may have to be revised at the Customer's expense at that time.

6. Liability and Force Majeure

PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) of the Connection Agreement ("**Part III**") and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of the Agreement. Unless the context otherwise requires, all references in Part III to "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 6, the parties agree that the references to:

- (i) the Transmitter in lines 3 and 4 of Section 15.1 of Part III means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
- (ii) the Customer in lines 3 and 4 of Section 15.2 of Part III means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

This Section 6 shall survive the termination of the Agreement.

7. Events of Default

7.1 Each of the following events shall constitute an "Event of Default" under the Agreement:

- (a) failure by the Customer to pay any amount due under the Agreement;
- (b) breach by the Customer or Hydro One of any term, condition or covenant of the Agreement; or
- (c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

7.2 Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Subsection 7.1(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 15 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 15 calendar day

v. 6 (August 2024)

period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the sum of the amounts payable by the Customer less any amounts already paid by the Customer under the terms of the Agreement.

7.3 Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Subsection 7.1(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 15 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 15 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

7.4 All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

8. Confidential Information

PART SEVEN: EXCHANGE AND CONFIDENTIALITY OF INFORMATION ("**Part 7**") and Sections 1.1.3 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of this Agreement. Unless the context otherwise requires, all references in Part 7 to "this Agreement" shall be deemed to be a reference to this Agreement.

9. Transmission Bypass

If the Project involves the installation of a Generation Facility by the Customer at the site of a load facility that is connected to or is connecting to the transmission system, the Customer acknowledges that Hydro One has informed the Customer that:

- (a) other than in the circumstances described in Section 11.2.3A of the Code, Hydro One is required

to collect bypass compensation (calculated in accordance with Section 11.2.6 of the Code) from the Customer under Section 11.2.1(b) of the Code if the Customer, while retaining its connection to Hydro One's transmission system, also connects its load facility to a Generation Facility such that the Customer reduces its load served directly by Hydro One's transmission system, and the line connection or transformation connection rates in relation to that facility will be reduced; and

(b) if the Generation Facility has an installed capacity of 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation and is being installed to displace all or any portion of the load demand at the load facility, the amounts invoiced by the IESO for line and transformation connection services applicable to the load facility will be calculated such that the customer demand in any hour will be the sum of: (a) the load-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by a Generation Facility in accordance with Note 3 of the Provincial Transmission Rates set out in the OEB-approved Uniform Transmission Rates (OEB-2021-0276)).

10. Assignment for Financing Purposes

(a) The Customer may, without the written consent of Hydro One, assign by way of security only all or any part of its rights or obligations under the Agreement to a Lender(s). The Customer shall promptly notify Hydro One, in writing, upon making such assignment.

(b) The Customer may disclose Confidential Information of Hydro One to a Lender or prospective Lender provided that the Customer has taken all precautions as may be reasonable and necessary to prevent unauthorized use or disclosure of Hydro One's Confidential Information by a Lender or prospective Lender.

(c) Where a notice of an Event of Default has been served on the Customer under Section 7.2, an agent or trustee for and on behalf of the Lender(s) ("**Security Trustee**") or a receiver appointed by the Security Trustee ("**Receiver**") shall upon notice to Hydro One be entitled (but not obligated) to exercise all of the rights and obligations of the Customer under the Agreement and shall be entitled to remedy the default specified in the notice of default within the cure period referred to in Section 7.2. Hydro One agrees to accept performance of the Customer's obligations under the Agreement by the Security Trustee or Receiver in lieu of the Customer's performance of such obligations, and will not exercise any right to terminate the Agreement due to an event of default if the Security Trustee, its nominee or transferee, or the Receiver acknowledges in

writing its intention to be bound by the terms of the Agreement by notifying Hydro One, and such acknowledgment is received within 20 days of the date of receipt by the Customer of the notice of default.

(d) the Lender will have no obligation or liability under the Agreement by reason of the assignment until such time as the Lender, the Security Trustee or the Receiver exercises any of the rights or obligations of the Customer under the Agreement.

(e) The Customer shall be deemed to hold the provisions of this Section 10 that are for the benefit of Lender(s) in trust for such Lender(s) as third party beneficiary(ies) under the Agreement.

11. Code and OEB-approved Transmission Connection Procedures

This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

- (a) *Transmission System Code*, the said provision shall be deemed to be amended so as to comply with the *Transmission System Code*; or
- (b) OEB-Approved Connection Procedures, the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures.

12. General

(a) Subject to Section 11, any amendment to the Agreement shall be made in writing and duly executed by both parties.

(b) Unless otherwise specified, references in the Agreement to Sections or Schedules are to sections, articles and Schedules of the Agreement. Any reference in the Agreement to any statute, regulation, any OEB-approved documents or any section thereof will, unless otherwise expressly stated, be deemed to be a reference to such statute, regulation, document or section as amended, restated or re-enacted from time to time. The insertion of headings is for convenience only, and shall not affect the interpretation of the Agreement. Unless the context requires otherwise, words importing the singular include the plural and vice versa. The words "including" or "includes" means including (or includes) without limitation.

(c) The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the

Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

- (d) Other than in accordance with Section 10 above, the Agreement may not be assigned without the written consent of the other party, which consent will not be unreasonably withheld.
- (e) The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.
- (f) Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.
- (g) The obligation to pay any amount due and payable hereunder shall survive the termination of the Agreement.



**CONNECTION AND COST RECOVERY AGREEMENT (CCRA) -
LOAD**

between

Hydro Ottawa Limited

and

Hydro One Networks Inc.

for

Russell TS - Transformer (T1 and T2) Upgrade

Hydro Ottawa Limited (the “**Customer**”) has requested and Hydro One Networks Inc. (“**Hydro One**”) has agreed to replace the end-of-life T1 and T2 (75 MVA) transformers with larger (100 MVA) transformers at **Russell TS** (the “**Project**”) on the terms and conditions set forth in this Connection Cost Recovery Agreement November 7, 2024 (the “**Agreement**”). The attached Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects V7 6-2023 (the “**Standard Terms and Conditions**” or “**T&C**”), and the following schedules attached hereto are to be read with and form part of this Agreement:

Schedule "A" - Scope of Hydro One Connection Work
Schedule "B" - Scope of Customer Connection Work
Schedule "C" - Capital Contribution(s), Payment Schedule, Revenue Requirements
Etc.

I. Project Summary

The two 75MVA transformer(s) T1 and T2 at Russell TS have reached end-of-life which means that Hydro One would normally have to perform the Avoided Cost Work (as defined below under the heading “**Additional Terms**”) to replace the transformer(s) like-for-like, at its own expense to continue to supply the Customer’s load. However, at the request of the Customer, Hydro One will perform the Hydro One Connection Work to replace the end-of-life 75 MVA transformer(s) with 100 MVA transformer(s) instead of performing the Avoided Cost Work to also meet the Customer’s load growth needs.

II. Term

The Term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date (the “**Term**”) unless terminated earlier in accordance with the terms of this Agreement.

III. Special Circumstances

1. **In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to the Customer:**
 - (a) executing and delivering this Agreement to Hydro One by no later than, November 7, 2024, (the “**Execution Date**”); and
 - (b) paying Hydro One all amounts required to be paid by the Customer on the execution of this Agreement.

2. Section 6.5.2 of the Transmission System Code permits the initial calculation of a Capital Contribution based on estimated costs provided that the Capital Contributions are recalculated based on the actual costs. The estimates of the Engineering and Construction Cost and the Capital Contributions specified in Schedule “C” of this Agreement were derived based on the following type of estimate performed by Hydro One at the Customer’s request



✓	Type of Estimate	Description	Typical Range of Estimate
✓	AACE* Class 3	Detailed Estimate: Prepared based on the completion of preliminary design activities which may include drawings, technical studies, and surveys. This estimate may represent 20% design definition and can include cost for materials/Procurement, Engineering and Project Management, Construction and Commissioning, Risk/Contingencies, Interest and Overheads.	+30% /- 20%**
N/A	AACE Class 4	Budgetary Estimate: Prepared based on the completion of conceptual estimate which may include sketches, review of existing drawings, and a site assessment at the connecting customer's expense and upon completion of the CCEA. This estimate may represent 10% design definition and can be summarized into cost of Materials/Procurement, Engineering, Project management cost and Construction and Commissioning cost.	+50/-30%**
N/A	AACE Class 5	Conceptual Estimate: Prepared based on the Customer's conceptual scope of work and is summarized into the following two basic groupings: <ul style="list-style-type: none"> ▪ Historical cost of Materials/Procurement ▪ Engineering, Project management, Construction and Commissioning. 	+100/-50%**
N/A	Planner's Estimate	High-level Ballpark Estimate for Preliminary Planning Purposes: Provided when the Customer wants to bypass the estimating stage of the Transmission Connection Process and go straight to project execution using the unit costs from a somewhat comparable project (which may not be recent if the work to be performed by Hydro One is rarely performed or rarely performed in certain areas of the province).	None but substantially less than AACE Class 5 Range

* Association for the Advancement of Cost Engineering

** AACE cost estimation system No. 18R-97.

Notwithstanding the type of estimate performed by Hydro One for the Project, the actual Engineering and Construction Cost of the Transformation Connection Pool Work; the Line Connection Pool Work and the Network Pool Work will be used to determine the actual capital contributions payable by the Customer for each of the pools as well as the Engineering and Construction Cost of the Work Chargeable to Customer.

The Range of Estimate provided in the table above for AACE estimates is indicative and not guaranteed by Hydro One. What the Range of Estimate does do is highlight the risk to the Customer that as the Range of Estimate for the type of estimate performed for the Project is less refined, the scope of the Hydro One Connection Work identified in Schedule "A" will contain a greater number of assumptions on the part of Hydro One which if they are incorrect may materially change the scope of the Hydro One Connection Work from what is identified in Schedule "A", delay the Ready for Service Date identified herein and/or increase the Engineering and Construction Cost of the Hydro One Connection Work and may also materially change the scope of the Customer Connection Work to be performed by the Customer from what is identified in Schedule "B".

IV. Premium Costs

The Customer acknowledges and agrees that in addition to the circumstances described in Section 16 of the Standard Terms and Conditions, Hydro One shall have the right to perform work at overtime rates and charge the Customer "Premium Costs" for same without obtaining the Customer's consent during transmission system outages taken to perform Hydro One Connection Work and/or commissioning.

V. Confidentiality Terms

The parties agree that section 1.1.3 (Definition of Confidential Information) and Part Seven of the Connection Agreement are incorporated herein and shall apply mutatis mutandis to this Agreement; provided that for purposes of the incorporated section 21.2 within such Part Seven of the Connection Agreement (for the purposes of this subsection (c), "**Section 21.2**"), Hydro One consents to the Customer disclosing Hydro One's Confidential Information to other persons as required for the development, construction, financing, and operation of the Customer's Local Distribution Company subject to the Customer complying with the requirement in Section 21.2 to ensure that such other persons comply with the confidentiality provisions set out in the incorporated Part Seven of the Connection Agreement

VI. Notice

Any written notice required by the Agreement shall be deemed properly given only if either e-mailed, mailed or delivered to the parties at the address identified below.

(a) If to Hydro One:

Hydro One Networks Inc.
483 Bay Street
14th Floor, South Tower
Toronto, Ontario M5G 2P5

Attention: Robert Reinmuller, P.Eng. VP, Transmission System Planning
& Large Customer
Robert.Reinmuller@HydroOne.com

(b) If to the Customer:

Hydro Ottawa Limited
2711 Hunt Club Rd
Ottawa Ontario K1G 5Z9

Attention: Guillaume Paradis, Chief Electricity Distribution Officer
e-mail address: guillaumeparadis@hydroottawa.com

VII/VIII. Terms Applicable to Avoided Cost Work

1) The Standard Terms and Conditions are hereby amended as follows:

(a) by adding the following terms:

"Avoided Cost –Line Connection Pool" means Hydro One's estimate of the Engineering and Construction Cost of the Avoided Cost Work - Line Connection Pool as identified in Schedule "C" of the Agreement.

"Avoided Cost – Network Pool" means Hydro One's estimate of the Engineering and Construction Cost of the Avoided Cost Work – Network Pool as identified in Schedule "C" of the Agreement.

"Avoided Cost - Transformation Connection Pool" means Hydro One's estimate of the Engineering and Construction Cost of the Avoided Cost Work - Transformation Connection Pool as identified in Schedule "C" of the Agreement.

“Avoided Cost Work” mean collectively, the Avoided Cost Work - Line Connection Pool, the Avoided Cost Work – Network Pool and the Avoided Cost Work - Transformation Connection Pool.

“Avoided Cost Work - Line Connection Pool” means the work identified in Schedule “A” of the Agreement under the heading “Avoided Cost Work - Line Connection Pool” that would have been performed by Hydro One to replace portions of its facilities that have reached end of life at its sole expense if the Customer had not requested that Hydro One perform the Line Connection Pool Work.

“Avoided Cost Work – Network Pool” means the work described in Schedule “A” of the Agreement under the heading “Avoided Cost Work –Network Pool” that would have been performed by Hydro One to replace portions of its facilities that have reached end of life at its sole expense if the Customer had not requested that Hydro One perform the Network Pool Allocated Work.

“Avoided Cost Work - Transformation Connection Pool” means the work described in Schedule “A” of the Agreement under the heading “Avoided Cost Work - Transformation Connection Pool” that would have been performed by Hydro One to replace portions of its facilities that have reached end of life at its sole expense if the Customer had not requested that Hydro One perform the Transformation Connection Pool Work.

(b) by replacing Section 10.1 with the following:

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Pool Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One:

- (a) a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work;
- (b) a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work;
- (c) a Capital Contribution towards the Pool Funded Cost of the Network Pool Allocated Work; and
- (d) any amounts payable to Hydro One under Subsection 12(a)(i) hereof.

For the purposes of determining the estimated and the actual Capital Contribution payable by the Customer for the:

- 1) Transformation Connection Pool Work, Hydro One shall deduct the Avoided Cost - Transformation Connection Pool from the Engineering and Construction Cost of the Transformation Connection Pool Work;
- 2) Line Connection Pool Work, Hydro One shall deduct the Avoided Cost – Line Connection Pool from the Engineering and Construction Cost of the Line Connection Pool Work; and

- 3) Network Pool Allocated Work, Hydro One shall deduct the Avoided Cost – Network Pool from the Engineering and Construction Cost of the Network Pool Allocated Work.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Pool Allocated Work is provided in Schedule “C” of the Agreement. An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Pool Allocated Work is specified in Schedule “C” of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule “C” of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule “C” to replace Schedule “C” of the Agreement attached hereto which shall identify the following:

- (i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
- (ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
- (iii) the actual Engineering and Construction Cost of the Network Pool Allocated Work;
- (iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
- (v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Pool Allocated Work; and
- (vi) the revised Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable; and
- (vii) the revised Avoided Cost – Line Connection Pool if Hydro One revised the Avoided Cost – Line Connection Pool in accordance with Section 10.5 below;
- (viii) revised Avoided Cost – Network Pool if Hydro One revised the Avoided Cost – Network Pool in accordance with Section 10.5 below; and/or
- (ix) the revised Avoided Cost – Transformation Connection Pool if Hydro One revised the Avoided Cost – Transformation Connection Pool in accordance with Section 10.5 below.

The new Schedule “C” shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contribution paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Pool Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule “C”. If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Pool Allocated Work, the Customer

shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "C".

(c) by adding the following as Section 10.5:

Subject to the foregoing, the Avoided Cost – Line Connection Pool, the Avoided Cost – Network Pool and the Avoided Cost - Transformation Connection Pool are fixed amounts. Should:

- (i) after commencing the Hydro One Connection Work, Hydro One determine, acting reasonably, that all or any portion of the scope of the Avoided Cost Work requires revision;
- (ii) Hydro One determine, acting reasonably, that there has been a Material change in the cost of any component used by Hydro One to estimate the cost of the Avoided Cost Work, including, but not limited to the cost of obtaining any approvals required under any Applicable Laws, obtaining land rights, labour, materials or equipment; and/or
- (iii) the Customer request that Hydro One perform another estimate of the cost of the Avoided Cost Work because the Customer reasonably believes that:
 - (a) all or any portion of the scope of the Avoided Cost Work requires revision; and/or
 - (b) that there has been a Material change in the cost of any component used by Hydro One to estimate the cost of the Avoided Cost Work,

Hydro One will perform another estimate of the cost of the Avoided Cost Work and provide the Customer with a:

- (a) revised Avoided Cost – Line Connection Pool;
- (b) revised Avoided Cost – Network ; and/or
- (c) revised Avoided Cost – Transformation Connection Pool,

in the new Schedule "C" to be provided by Hydro One in accordance with Section 10.1 above.

- 2) Any reference to Hydro One Connection Work as it appears in Section 5 of the Standard Terms and Conditions shall be deemed to include any work being performed by Hydro One at **Russell TS** to replace other end-of-life transmission equipment and facilities that are not the subject of the Customer's upgrade request.
- 3) Not with standing Part 6 of Schedule A of this Agreement, as the main purpose of the Project is for Hydro One to replace end-of-life transmission equipment, Hydro One: (i) reserves the right to reject any Customer Initiated Scope Changes for any reason whatsoever; and (ii) will implement all Non-Customer Initiated Scope Change(s).

IX/X. General

- (a) Subject to Section 31 of the Standard Terms and Conditions, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.



- (b) This Agreement will supersede the terms of any purchase orders issued by the Customer to Hydro One in respect of the Project irrespective of whether same have been issued by the Customer and/or accepted by Hydro One on or after the execution of this Agreement by the Customer.

- (c) This Agreement may be executed by the parties in writing or via electronic signatures and in one or more counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be delivered via fax, electronic mail (in portable document format) or other transmission method and any counterpart so delivered is deemed to have been duly and validly delivered and be valid and effective for all purposes.

[Signature page follows]



IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO OTTAWA LIMITED

DocuSigned by:
Guillaume Paradis 2024-11-06
A8115E39C3334D4

Name: Guillaume Paradis
Title: Chief Operating Officer - Distribution and Generation

Name:
Title:
I/We have the authority to bind the Corporation.

HYDRO ONE NETWORKS INC.

Signed by:
Robert Reinmuller
24DC60889B73411...

Name: Robert Reinmuller P.Eng.
Title: Vice President, Transmission System Planning & Large Customer
Execution Date: November 10, 2024
I have the authority to bind the Corporation

Schedule “A” Russell TS – Transformer (T1 and T2) Upgrade: Scope of Hydro One Connection Work

MISCELLANEOUS

New or Modified Connection Facilities: Two (2) 100 MVA transformers at Russell TS (T1 and T2).

Connection Point: Russell TS - T1 and T2

Approval Date (if Section 92 required to be obtained by Hydro One – Not Applicable

Ready for Service Date: June 30, 2027

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work.

AVOIDED COST WORK:

Hydro One would have had to provide project management, engineering, equipment and material, construction and commissioning of new and modified Hydro One facilities with respect to the following work but for the Customer’s upgrade request:

Avoided Cost Work - Transformation Connection Pool

- Replacement of the existing Russell TS T1 [75 MVA] and T2 [75 MVA] with two new 75 MVA transformers.
Replace HV and LV transformer Surge Arresters with new HV and LV Surge Arresters for the new T1/T2 transformers
- Replace 115kV transformer disconnect switches, T1-L and T2-L, with new 115kV transformer disconnect switches for the new T1/T2 transformers
- Replace 115kV switch, 36A6R-48 with new 115kV line disconnect switch and relocate between new (T1/T2) and old (T1/T2) transformer taps.
- Install the old 36A6R-48 switch and relocate on A5RK Riverdale side (36A5RK-ILS).
- Perform AC and DC load studies to ensure AC and DC equipment is sized and rated appropriately and meet Hydro One standards.
- Separate AC/DC supply from Hydro Ottawa. New AC SS and DC SS that meets current Hydro One standards will be part of new PCT building.
- Replace existing AC station service transformers, TSS1 and TSS2, with new outdoor station service transformers and rated appropriately pending AC load study results.
- Replace all associated protection, control and telecom facilities to current Hydro One standards as per “**Protection & Automation (PA) Requirements**” document (shown in Appendix E)
- Replace 115kV A5RK PT with new Hydro One standard CVT
- Relocate existing A6RCVT and replace secondary fuse box as per Hydro One’s latest standard.
- Install new spill containments to accommodate the new transformers and meet current Hydro One standards and MOECC regulations.
- Replace any cap & pin, multi-cone, and porcelain strain insulators in the 115kV switchyard.

Avoided Cost Work - Line Connection Pool

None

Avoided Cost Work – Network Pool

None

GENERAL:

Hydro One will provide project management, engineering, equipment and material, construction and commissioning of the Hydro One Connection Work. The scope of the Hydro One Connection Work is based on the requirements from:

- the IESO's System Impact Assessment (SIA) Report dated October 07, 2024 (CAA ID #2024-EX1280);

Hydro One, or its agents:

- (i) will supply and install all materials and equipment not specifically described herein that are required or may be necessary to complete the work for the purpose required;
- (ii) shall repair any damage caused to lands, owned by Hydro One or third parties, associated with or related to the Hydro One Connection Work;
- (iii) where Hydro One deems necessary, install appropriate solutions to address public safety concerns regarding the facilities being constructed by Hydro One, which may include, but is not limited to, safety enclosures and signage; and
- (iv) scrap all materials and equipment removed by Hydro One, or its agents, at site unless specifically stated otherwise.

SCOPE DETAILS (BY CATEGORY):**Part 1: Transformation Connection Pool Work**

Hydro One will:

- Replace the existing T1 and T2 75 MVA transformers with new larger "115-F" 115-13.8-13.8 kV, 60/100 MVA units in a new location within existing station site. Also, provide the incremental cost for upsizing the 75MVA transformers to 100MVA transformers.
- Replace HV and LV transformer Surge Arresters with new HV and LV Surge Arresters for the new T1/T2 transformers
- Replace 115kV transformer disconnect switches, T1-L and T2-L, with new 115kV transformer disconnect switches for the new T1/T2 transformers
- Replace 115kV switch, 36A6R-48 with new 115kV line disconnect switch and relocate between new (T1/T2) and old (T1/T2) transformer taps.
- Install the old 36A6R-48 switch and relocate on A5RK Riverdale side (36A5RK-ILS).
- Perform AC and DC load studies to ensure AC and DC equipment is sized and rated appropriately and meet Hydro One standards.
- Separate AC/DC supply from Hydro Ottawa. New AC SS and DC SS that meets current Hydro One standards will be part of new PCT building.
- Replace existing AC station service transformers, TSS1 and TSS2, with new outdoor station service transformers and rated appropriately pending AC load study results.

- Replace all associated protection, control and telecom facilities to current Hydro One standards as per “**Protection & Automation (PA) Requirements**” document (shown in Appendix E)
- Replace 115kV A5RK PT with new Hydro One standard CVT
- Relocate existing A6RCVT and replace secondary fuse box as per Hydro One’s latest standard.
- Install new spill containments to accommodate the new larger 100MVA transformers and meet current Hydro One standards and MOECC regulations.
- Replace any cap & pin, multi-cone, and porcelain strain insulators in the 115kV switchyard.

Part 2: Line Connection Pool Work

None

Part 3: Network Pool Allocated Work

None

Part 4: Network Pool Work (Non-Recoverable from Customer)

None

Part 5: Work Chargeable to Customer

None

Part 6: Scope Change

For the purposes of this Part 6 of Schedule “A”, the term “**Non-Customer Initiated Scope Change(s)**” means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule “A” as a result of any one or more of the following:

- any environmental assessment(s);
- requirement for Hydro One to obtain approval under Section 92 (leave to construct) of the Ontario Energy Board Act if the transmission line route selected by Hydro One is greater than 2 km in length;
- Hydro One having to expropriate property under the Ontario Energy Board Act;
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the Ontario Energy Board Act or any approval issued by the OEB to expropriate under the Ontario Energy Board Act; and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in this Schedule “A” whether they are initiated by the Customer (“**Customer Initiated Scope Changes**”) or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule “C” of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer Initiated Scope Changes to this Project must be made in writing to Hydro One. Hydro One will advise the Customer of any cost and schedule impacts of any Customer Initiated Scope Changes.

Hydro One will not implement any Customer Initiated Scope Changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes. Hydro One will implement all Non-Customer Initiated Scope Changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer Initiated Scope Changes reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

- (i) the Transformation Connection Pool Work,
- (ii) the Line Connection Pool Work;
- (iii) Network Pool Work;
- (iv) Network Pool Allocated Work; and
- (v) The Work Chargeable to Customer.

At that point, no further Non-Customer Initiated Scope Changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

Schedule “B” Russell TS – Transformer Upgrade (T1 and T2): Scope of Customer Connection Work

MISCELLANEOUS

Revenue Metering: IESO compliant revenue metering to be provided by the Customer.

GENERAL:

The Customer will:

- (a) enter into a Connection Agreement with Hydro One or where applicable, amend its existing Connection Agreement with Hydro One at least 14 days prior to the first Connection;
- (b) ensure that project data is provided to Hydro One in accordance with Subsection 3(e) of the T&C;
- (c) install metering facilities in accordance with the Market Rules;
- (d) provide a dedicated communication circuit for remote access to the metering equipment in accordance with the Market Rules;
- (e) provide a dedicated telephone line for direct communication between Hydro One’s Integrated System Operating Centre (“**Hydro One ISOC**”) operator and the real time contact to be listed in the Connection Agreement can be a toll free (1-800...) phone number which should go directly to the Customer’s real time contact and not an automated teleprompt/voice recording as it may require an immediate response from the Customer) and will provide round-the-clock monitoring and control of the Customer’s facilities;
- (f) ensure that the work to be performed by the Customer required for successful installation, testing and commissioning of protective, teleprotection, telecommunication and metering equipment is completed as required to enable Hydro One COVER verification to confirm satisfactory performance of such systems;
- (g) accept operating designations as assigned by Hydro One and install nameplates on the Customer’s equipment;
- (h) use operating designations on all operating agreements, telemetry and protection documents and any other agreements that refer to equipment designation; and
- (i) satisfy all other requirements specific to the Connection.

LAND RIGHTS REQUIRED TO BE PROVIDED BY CUSTOMER: None

DOCUMENTATION REQUIREMENTS: None



Schedule “C” Russell TS – Transformer Upgrade (T1 and T2): Capital Contribution(s), Payment Schedule, Revenue Requirements Etc.

MISCELLANEOUS

Risk Classification: Low Risk

True-Up Points:

- a. following the fifth and tenth anniversaries of the In-Service Date; and following the fifteenth anniversary of the In-Service Date

Customer’s HST Registration Number: [REDACTED]

Security Requirements: None

Security Date: Not applicable

Existing Load Table:

	A	B
Existing Load Facility	Existing Load (MW)¹	Normal Capacity (MW)^{2,1}
Russell TS	62.0	73.9

Existing Load Table Notes:

- ¹ Existing Load means the Customer’s Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the Transmission System Code).
- ² Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 11.2.8 of the Transmission System Code and Hydro One’s OEB-approved Transmission Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.
- ³ Power Factor of 0.95 is assumed.

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: \$50,600,000

Estimate of Transformation Connection Pool Work Capital Contribution: \$0 plus HST of \$0

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: To be provided 180 days after the Ready for Service Date.

Actual Transformation Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date.

Avoided Cost - Transformation Connection Pool: \$50,167,883

Revised Avoided Cost –Transformation Connection Pool: To be provided 180 days after the Ready for Service Date.



LINE CONNECTION POOL WORK

Not Applicable

NETWORK POOL ALLOCATED WORK

Not Applicable

**NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):
WORK CHARGEABLE TO CUSTOMER**

Not Applicable

**MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS
AND WORK CHARGEABLE TO CUSTOMER**

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Pool Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the payments specified below on or before the Payment Milestone or Payment Date specified below. Other than for payments made prior to or due upon execution of this Agreement by the Customer, Hydro One will invoice the Customer 30 days prior to each Payment Milestone or Payment Date.

Payment Milestone or Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Pool Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
N/A	N/A	N/A	N/A	N/A	N/A



**TRANSFORMATION CONNECTION REVENUE REQUIREMENTS
AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES**

Annual Period Ending On:	New Load** (MW)	Part of New Load (MW) Exceeding Normal Capacity of Existing Load Facilities [A] <small>(Note A)</small>	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k\$) for True-Up, based on [A] or [B], whichever is applicable
1 st Anniversary of In Service Date	6.5	0.0	0.0	0.0
2 nd Anniversary of In Service Date	8.4	0.0	0.0	0.0
3 rd Anniversary of In Service Date	10.4	0.0	0.0	0.0
4 th Anniversary of In Service Date	12.0	0.3	0.1	3.0
5 th Anniversary of In Service Date	13.3	1.1	0.3	11.7
6 th Anniversary of In Service Date	14.6	2.2	0.6	23.0
7 th Anniversary of In Service Date	15.9	3.3	0.9	34.3
8 th Anniversary of In Service Date	17.2	4.3	1.2	45.6
9 th Anniversary of In Service Date	18.4	5.4	1.5	56.5
10 th Anniversary of In Service Date	19.6	6.4	1.7	66.9
11 th Anniversary of In Service Date	20.8	7.4	2.0	77.4
12 th Anniversary of In Service Date	22.1	8.4	2.3	88.2
13 th Anniversary of In Service Date	23.3	9.5	2.6	99.1
14 th Anniversary of In Service Date	24.4	10.4	2.8	108.7
15 th Anniversary of In Service Date	25.4	11.2	3.1	117.4
16 th Anniversary of In Service Date	26.4	12.0	3.3	126.1
17 th Anniversary of In Service Date	27.4	12.9	3.5	134.8
18 th Anniversary of In Service Date	28.5	13.7	3.7	143.9
19 th Anniversary of In Service Date	29.9	14.9	4.1	156.6
20 th Anniversary of In Service Date	31.7	16.4	4.5	171.8
21 st Anniversary of In Service Date	33.4	17.8	4.9	187.0
22 nd Anniversary of In Service Date	35.2	19.3	5.3	202.7
23 rd Anniversary of In Service Date	37.0	20.8	5.7	218.3
24 th Anniversary of In Service Date	38.8	22.3	6.1	234.0
25 th Anniversary of In Service Date	40.6	23.1	6.3	241.8

**LINE CONNECTION REVENUE REQUIREMENTS
AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES**

Not Applicable

**NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST
AT THE NEW OR MODIFIED CONNECTION FACILITIES**

Not Applicable

Notes Applicable to All of the Above Revenue Requirements Tables:

A New Load is based on Customer’s Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. “Overload” is derived in accordance with Section 11.2.8 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One’s connection facilities.

Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects

1. Each party represents and warrants to the other that:

- (a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
- (b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
- (c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;
- (d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;
- (e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
- (f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The HST registration number for Hydro One is [REDACTED] and the HST registration number for the Customer is as specified in Schedule "C" of the Agreement; and
- (g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

- (a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required

for the construction, Connection and operation of the New or Modified Connection Facilities;

- (b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) in accordance with Hydro One's rights under section 6.1.11 of the Transmission System Code, the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) in accordance with section 4.3.3 and 4.3.4 of the Transmission System Code, Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

- (h) Hydro One is not permitted to Connect any

new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) in accordance with section 6.1.11 of the Transmission System Code, Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the Transmission System Code, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in accordance with section 4.3.2 of the Transmission System Code, Hydro One shall provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the Transmission System Code, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 of the Connection Agreement shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use reasonable efforts to ensure that any applications required to be filed to

obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

- (a) specifications of the protection equipment on the Customer's side of the Connection Point;
- (b) acceptance of power system components on the Customer's side of the Connection Point;
- (c) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
- (d) participation in the commissioning, inspection or testing of the Customer's Facilities.

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

- (a) the Customer is in compliance with its obligations under the Agreement;
- (b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
- (c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work;
- (d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as

that term is defined in the *Transmission System Code*) or a Force Majeure Event;

- (e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
- (f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*, such leave is obtained on or before the date specified as the Approval Date in Schedule “A” of the Agreement;
- (g) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws to perform all or any part of the Hydro One Connection Work:
 - (i) environmental approvals, permits or certificates;
 - (ii) land use permits from the Crown; and
 - (iii) building permits and site plan approvals;
- (h) Hydro One is able, using reasonable efforts, to obtain all Land Rights to be obtained for the Project (as identified in Schedule “A” and/or “B” of the Agreement) on terms substantially similar to the forms of the Land Rights attached as schedules to and forming part of the Agreement, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;
- (i) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and
- (j) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

- 6. Upon completion of the Hydro One Connection Work:
 - (a) Hydro One shall own, operate and maintain all equipment specified in Schedule “A” of the Agreement under the heading “Ownership”; and
 - (b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by

Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

- (i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and
- (ii) any portion of the equipment referred to in (a) above that is located on the Customer’s property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer’s property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer’s Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer’s side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One’s requirements to permit Connection of the New or Modified Connection Facilities to Hydro One’s transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer’s facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer’s apparatus that might affect the proper functioning of Hydro One’s reclosing equipment.

9. The Customer shall provide Hydro One with

copies of the documentation specified in Schedule “B” of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One’s ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer’s Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule “C” of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule “C” of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule “C” of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a cost breakdown substantially in the form of the cost breakdown shown in the form of Monthly Cost Report attached to Agreement as Schedule “D” together with a new Schedule “C” to replace Schedule “C” of the Agreement attached

hereto which shall identify the following:

- (a) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
- (b) the actual Engineering and Construction Cost of the Line Connection Pool Work;
- (c) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
- (d) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
- (e) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
- (f) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule “C” shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contribution paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule “C”. If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule “C”.

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

- (a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs; or
- (b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer.

10.3 Should Hydro One require the Customer to make a Capital Contribution towards Network Pool

Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 20 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof for the construction or modification of a Hydro One-owned Connection Facility other than an enabler facility and where this Capital Contribution includes the cost of capacity on the Connection Facility in excess of the Customer's needs, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.3.17A of the *Transmission System Code* if that capacity is assigned to another Load Customer within fifteen (15) years of the In Service Date of the Connection Facility.

11. Hydro One shall perform a True-Up, based on Actual Load:

- (a) at the True-Up Points specified in Schedule "C" of the Agreement; and
- (b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

- (i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable,

and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

- (ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code*.

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code*) during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-

Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14. Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code*.

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1 The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described as Work Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "C" of the Agreement in the manner specified in Schedule "C" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

- (a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or
- (b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 18 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility: If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, in accordance with the requirements of Schedule J of the Connection Agreement prior to transferring load from the Existing Load Facility. Upon receiving the notice, Hydro One will proceed in accordance with Section 11.2.2 of the *Transmission System Code* and the applicable terms of the Connection Agreement.

17.2 Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load: Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One in accordance with the requirements of Schedule J of the Connection Agreement, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential bypass situation in accordance with the OEB-Approved Connection Procedures and its obligations in Section 11.2.2 of the Code and the applicable terms of the Connection Agreement. If the Customer does not intend to by-pass the Existing

Load Facility, the Customer must, in accordance with the OEB-Approved Connection Procedures:

- (a) notify Hydro One and the OEB within 30 days of receiving Hydro One’s notification of potential by-pass, that it has no intention of bypassing Hydro One’s Existing Load Facility;
- (b) transfer the load back to the Existing Load Facility within an agreed time period; and
- (c) compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be terms of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One’s Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs (the “**Cancellation/ Termination Costs**”).

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

- (a) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer’s sole expense, to continue with the purchase of the materials and transfer title to those materials on

an “as is, where is basis” to the Customer upon the Customer paying Hydro One’s Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or

- (b) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer’s sole expense, to transfer title to the materials on an “as is, where is basis” to the Customer upon the Customer paying Hydro One’s Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or
- (c) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer’s sole expense, to: transfer title to the materials on an “as is, where is basis” to the Customer upon the later of (A) the Customer paying Hydro One’s Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

Hydro One shall provide the Customer with an invoice for the Cancellation/Termination Costs payable under this Section 18 together with a cost breakdown of the Termination/Cancellation Costs substantially in the form of the cost breakdown shown in the form of Monthly Cost Report attached to the Agreement as Schedule “D”.

Part F: Sale, Lease, Transfer or Other Disposition of Customer’s Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer’s Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer’s Facilities are transferred or disposed to enter into an

assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash (by way of a certified cheque, bank draft or wire transfer), a Letter of Credit in a form acceptable to Hydro One or a Surety Bond in a form acceptable to Hydro One, the Customer shall furnish such security in the amount and by the dates specified in Schedule "C" of the Agreement.

A Security Deposit provided in the form of a letter of credit or a surety bond shall not expire prior to the Security Date specified in Schedule "C." If a letter of credit or surety bond has an earlier expiry date, Hydro One may draw down on the letter of credit or surety bond not more than 60 days prior to the expiry date and treat the amount drawn as a cash deposit.

Hydro One shall return the security deposit to the Customer as follows:

- (a) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and
- (b) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid under Section 10.1 hereof.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. All disputes, including, but not limited to, disputes related to:

- (a) the cost and the allocation of the costs under this Agreement;
- (b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
- (c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. In accordance with Section 12.1.3 of the Transmission System Code, if a dispute arises while a transmitter is New or Modified Connection Facilities, the transmitter shall not cease work or slow the pace of work without leave of the Board.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement. This obligation shall survive the termination of this Agreement.

Part I: Land Rights

24. Any Land Rights required by Hydro One for the Hydro One Connection Work are identified in Schedule "A" of the Agreement (if the Land Rights are to be obtained from third parties) and specified in Schedule "B" of the Agreement (where Hydro One requires Land Rights from the Customer). The acquisition of Land Rights includes acquiring the Land Rights and any approvals related thereto (e.g. municipal consents for access and access or entry permits).

With respect to the acquisition of Land Rights, including, the addition of lands to Hydro One's Provincial Master Land Use Permit, the Engineering and Construction Cost of same includes, but is not limited to, the purchase (price),

easements/lease/licence costs along with any associated costs such as the cost of performing appraisals, surveys, submitting applications, licence and review fees, legal and land disbursement closing costs and the cost of any special studies that might arise in the calculation of compensation in respect of the land rights (i.e. aggregate).

The Customer acknowledges and agrees that Hydro One shall only compensate third parties for Land Rights on commercially reasonable terms that are consistent with Hydro One's land acquisition policies.

If specified in Schedule "B" that the Customer is required to provide Hydro One with the Land Rights described in Schedule "B" of the Agreement, the Customer shall provide such Land Rights in accordance with the requirements of Schedule "B" including, without limitation, by the dates specified therein and such Land Rights shall be first in priority except as noted therein, in registerable form and provided to Hydro One with nominal consideration.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

- (a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 18 within the time stipulated for payment;
- (b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
- (c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by

the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

- (a) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or
- (b) the amounts payable under Section 16 and 18 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c)), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any

of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms of this Agreement and the parties shall follow the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY

AND FORCE MAJEURE TO “this Agreement” shall be deemed to be a reference to the Agreement and all references to “the Transmitter” shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the parties agree that the references in PART III: LIABILITY AND FORCE MAJEURE to:

- (a) the Transmitter in lines 3 and 4 of Section 15.1 of the Connection Agreement means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
- (b) the Customer in lines 3 and 4 of Section 15.2 of the Connection Agreement means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

- (a) *Transmission System Code*, the said provision shall be deemed to be amended so as to comply with the *Transmission System Code*;
- (b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
- (c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of a party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. In the Agreement:

- Words importing the singular include the plural and vice versa.
- Words importing a gender include any gender.
- Words importing a person include (i) an individual, (ii) a company, sole proprietorship, partnership, trust, joint venture, association, corporation or other private or public body corporate; and (iii) any government, government agency or body, regulatory agency or body or other body politic or collegiate.
- A reference to a person includes that person's successors and permitted assigns. A reference to a body, whether statutory or not, that ceases to exist or whose functions are transferred to another body is a reference to the body that replaces it or that substantially succeeds to its powers or functions.
- Where a word or phrase is defined in the Agreement, these Standard Terms and Conditions, the Transmission System Code, the *Ontario Energy Board Act, 1998* or the *Electricity Act, 1998*, other parts of speech and grammatical forms of the word or phrase have a corresponding meaning.
- A reference to a document (including a statutory instrument) or a provision of a document includes any amendment or supplement to, or any replacement of, that document or that provision.
- The expression "including" means including.

34. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

37. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 18

or 23 shall survive the termination of the Agreement.

Appendix “A”: Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* (some of which refer to definitions in the *Electricity Act, 1998* or the *Ontario Energy Board Act, 1998*) and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

“**Actual Load**” means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

“**Assigned Capacity**” is calculated in accordance with Section 6.2.2 of the *Transmission System Code*.

“**Adjusted Load Forecast**” means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

“**Agreement**” means the Connection Cost Recovery Agreement, the Schedules attached thereto, these Standard Terms and Conditions and where applicable (as indicated in the Connection Cost Recovery Agreement), the Contestable Work Terms and Conditions.

“**Applicable Laws**” means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission board, court authority or agency.

“**Approval Date**” means for the purpose of Subsection 5(f) of these Terms and Conditions, the date specified in Schedule “A” of the Agreement.

“**Capital Contribution**” means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code*.

“**Capital Contribution**” means a capital

contribution calculated using the economic evaluation methodology set out in the *Transmission System Code*.

“**Connect and Connection**” has the same meaning ascribed to the term “Connect” in the *Transmission System Code*.

“**Connection Agreement**” means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

“**Connection Facilities**” has the meaning set forth in the *Transmission System Code*.

“**Connection Point**” has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule “A” of the Agreement.

“**Contestable Work Terms**” means the Terms and Conditions for Contestable Work July 2021 including Attachment 1 and Attachment 2 attached thereto.

“**Customer Connection Work**” means the work to be performed by the Customer, at its sole expense, which is described in Schedule “B” of the Agreement.

“**Customer Connection Risk Classification**” is as specified in Schedule “C” of the Agreement.

“**Customer’s Facilities**” has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer’s Facilities.

“**Customer’s Property(ies)**” means any lands owned by the Customer in fee simple or where the Customer has easement rights.

“**Distributor**” has the meaning set forth in the *Transmission System Code*.

“**Economic Evaluation Period**” means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule “C” of the Agreement.

“**Engineering and Construction Cost**” means Hydro One’s charge for equipment, labour and materials at Hydro One’s standard rates plus Hydro One’s standard overheads as well as interest during construction using Hydro One’s capitalization rate in

effect during the construction period.

“**Electricity Act, 1998**” means the *Electricity Act, 1998* being Schedule “A” of the *Energy Competition Act, S.O. 1998*, c.15, as amended.

“**Existing Load**” in relation to the Customer and each of the Existing Load Facilities is equal to the Customer’s Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

“**Existing Load Facility(ies)**” means the connection facility(ies) owned by Hydro One as specified in the Existing Load Table in Schedule “C” of the Agreement where the Customer has Existing Load.

“**Force Majeure Event**” has the meaning ascribed thereto in the Connection Agreement.

“**HST**” means the Harmonized Sales Tax.

“**Hydro One Connection Work**” means the work to be performed by Hydro One, which is described in Schedule “A” of the Agreement.

“**Hydro One Facilities**” means Hydro One’s structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

“**Hydro One’s Property(ies)**” means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

“**IESO**” means the Independent Electricity System Operator continued under the *Electricity Act, 1998*.

“**In Service Date**” has the same meaning ascribed to the term “comes into service” in the *Transmission System Code*.

“**Incremental Network Load**” means the Customer’s New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One’s connection facilities.

“**Interest**” means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code*.

“**Land Rights**” means any one or more of the following real estate rights/land agreements and any

approvals required by Hydro One related thereto (e.g. municipal consents for access and access or entry permits) that are required for all or any part of the Hydro One Connection Work:

- (i) a grant(s) of easement in gross substantially in the form of the Grant of Easement in Gross attached to the Agreement as Schedule “E” from the registered owner(s) of the Easement in Gross Lands for the Easement in Gross Term to be obtained by the date specified as the Easement in Gross Date, with the Easement in Gross Lands, Easement in Gross Term and the Easement in Gross Date being specified in either Schedule “A” of the Agreement (registered owner is a third party) or “B” (registered owner is the Customer), as applicable;
- (ii) an access easement substantially in the form of the Access Easement attached to the Agreement as Schedule “F” from the registered owner(s) of the Access Easement Lands for the Access Easement Term to be obtained by the date specified as the Access Easement Date, with the Access Easement Lands, Access Easement Term and the Access Easement Date being specified in either Schedule “A” of the Agreement (registered owner is a third party) or “B” (registered owner is the Customer), as applicable. All municipal consent(s) and approvals for any access road easements required by Hydro One for all or any part of the Hydro One Connection Work must also be obtained by the Access Easement Date;
- (iii) an easement is required for an access road for a term beyond 21 years, as an access road easement for a term beyond 21 years may be viewed as not being exempt use by a utility with specific reference to s. 50(3) of the Planning Act (the “Act”) as the Act mentions a distribution line, transmission line etc. but with no reference to an access road and some municipalities however have viewed this differently and consider an access as ancillary and part of what is described in s. 50(3) of the Act and therefore is exempt from the municipal consent process, in such a case, Hydro One will need to either (a) secure municipal consent for the access road or (b) obtain a letter from the municipality stating that the access easement, beyond 21 years is for Hydro One and that the municipality considers access as part of the works described in the Act and therefore is not subject to the consent process;

- (iv) early access agreement is required substantially in the form of the Early Access Agreement attached to the Agreement as Schedule “G” from the registered owner(s) of the Early Access Lands to be obtained by the date specified as the “Early Access Execution Date” with the Early Access Lands and the Early Access Execution Date being specified in either Schedule “A” of the Agreement (registered owner is a third party) or “B” (registered owner is the Customer), as applicable;
- (v) an Off-Corridor Access Agreement is required substantially in the form of the Off-Corridor Access Agreement attached to the Agreement as Schedule “H” from the registered owner(s) of the Off-Corridor Access Lands to be obtained by the date specified as the “Off-Corridor Access Execution Date” with the Off-Corridor Access Lands and the Off-Corridor Access Execution Date being specified in either Schedule “A” of the Agreement (registered owner is a third party) or “B” (registered owner is the Customer), as applicable;
- (vi) a Construction Staging and Stringing Area Agreement is required substantially in the form of the Construction Staging and Stringing Area Agreement attached to the Agreement as Schedule “I” from the registered owner(s) of the Construction Staging and Stringing Area Land(s) to be obtained by the date specified as the Construction Staging and Stringing Area Execution Date with the Construction Staging and Stringing Area Land(s) and the Construction Staging and Stringing Area Execution Date being specified in either Schedule “A” of the Agreement (registered owner is a third party) or “B” (registered owner is the Customer), as applicable;;
- (vii) ownership/fee simple rights are required, Hydro One will enter into an Agreement of Purchase and Sale with the registered owner(s) of the “Lands to be Acquired” substantially in the form of the Agreement of Purchase and Sale attached to the Agreement as Schedule “J” for consideration that is consistent with Hydro One’s land acquisition policies with a closing date that is not to be later than the date specified as the “Closing Date” with the Lands to be Acquired and the Closing Date being specified in either Schedule “A” of the Agreement (registered owner is a third party) or “B” (registered owner is the Customer), as applicable;
- (viii) a Material Laydown Area Agreement is required substantially in the form of the Material Laydown Area Agreement attached to the Agreement as Schedule “K” from the registered owner(s) of the Material Laydown Area Land(s) to be obtained by the date specified as the Material Laydown Execution Date with the Material Laydown Area Land(s) and the Material Laydown Area Execution Date being specified in either Schedule “A” of the Agreement (registered owner is a third party) or “B” (registered owner is the Customer), as applicable;
- (ix) where all or any part of the Hydro One Connection Work is to be located on Crown land (MNR), Hydro One will need to obtain a Work Permit/Letter of Authority from the Ministry of Natural Resources (MNR) by no later than the date specified in Schedule “A” as the “Date Work Permit/Letter of Consent Required” to allow Hydro One to construct the portion of the Hydro One Connection Work to be located on the Crown land and add same to Hydro One’s Provincial Master Land Use Permit;
- (x) approvals from pipelines and/or railway companies are required, Hydro One will secure such approvals from the pipeline companies and/or railway companies listed in Schedule “A” of the Agreement as the “Affected Pipeline/Railway Companies” (including, but not limited to performing any necessary studies to obtain same) by the Railway/Pipeline Approval Date specified in Schedule “A”;
- (xi) consultations with third party encumbrancers are required, Hydro One shall consult with such third party encumbrancers to ensure that no project delays are experienced by Hydro One; and
- (xii) confirmation of Hydro One’s rights to use an existing (Unopened) road allowance is required, to all or any portion of the Hydro One Connection Work Hydro One shall obtain written confirmation from the municipality that Hydro One has all necessary rights and permission to construct and to access all or any portion of a transmission line being built by Hydro One along the unopened road allowance described as the Unopened Road Allowance Lands in Schedule “A”.

“**Letter of Credit**” means a letter of credit that meets all the following requirements:

- (a) is issued by a bank listed in Schedule I or II of the *Bank Act* (Canada) (“**Bank**”);
- (b) allows for presentment in Toronto, Ontario or presentment using a valid fax number where the Bank does not have a branch in Toronto, Ontario;
- (c) has an expiry date that is acceptable to Hydro One;
- (d) provides that any notice that the Bank does not wish to extend the letter of credit for any additional period of expiry must be provided, in writing, to Hydro One Networks Inc., 483 Bay Street, 7th Floor, South Tower, Toronto, Ontario M5G 2P5 Attn: Treasurer at least sixty (60) days prior to any expiration date;
- (e) permits partial drawings and multiple presentations;
- (f) provides that drawings will be paid on written demand without the issuing Bank enquiring whether Hydro One has a right as between itself and the Customer to make such demand, and without recognizing any claim of the Customer;
- (g) only requirement to be met in order to draw on the letter of credit is that Hydro One present the letter of credit and a certificate stating that the amount demanded is payable to Hydro One by the Customer pursuant to the terms of the Connection and Cost Recovery Agreement made between Hydro One Networks Inc. and the Customer, as it may be amended by the Customer and Hydro One from time to time;
- (h) provides that banking charges and commissions associated with the letter of credit are payable by the Customer;
- (i) subject to the International Standby Practices "ISP 98" ICC Publication no. 590 (“**ISP 98**”);
- (j) provide that notwithstanding ISP 98, in the event that the original of the letter of credit is lost, stolen, mutilated or destroyed, the Bank will agree to replace same upon written notice from Hydro One setting out the circumstances;
- (k) provides that matters not expressly covered by ISP 98, will be governed by the laws of the Province of Ontario and the laws of Canada applicable therein; and
- (l) any dispute or claim shall be submitted to the exclusive courts within the jurisdiction of the Province of Ontario.

“**Line Connection Pool Work**” means the Hydro One Connection Work specified in Schedule “A” of the Agreement under the heading “Line Connection Pool Work”.

“**Line Connection Revenue**” means the amount of line connection revenue attributable to that part of the Customer’s New Load to be received by Hydro One

through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

“**Line Connection Service Rate**” means the line connection service rate approved by the OEB in Hydro One’s Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

“**Load Customer**” has the meaning set forth in the *Transmission System Code*.

“**Load Forecast**” means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

“**Market Rules**” means the rules promulgated under Section 32 of the Electricity Act, 1998.

“**Material**” relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

“**Network Customer Allocated Work**” means the construction of or modifications to Network Facilities specified in Schedule “A” of the Agreement under the heading “Network Customer Allocated Work” that are minimum connection requirements.

“**Network Facilities**” has the meaning set forth in the *Transmission System Code*.

“**Network Pool Work**” means the Hydro One Connection Work specified in Schedule “A” of the Agreement under the heading “Network Pool Work”.

“**Network Revenue**” means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

“**Network Service Rate**” means the network service rate approved by the OEB in Hydro One’s Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

“**New Load**” means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

“New or Modified Connection Facilities” means the new or modified Hydro One Facilities constructed or modified by Hydro One as part of the Hydro One Connection Work.

“Normal Capacity” means, where the Customer is:

- (a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and
- (b) one of two or more Load Customers served by an Existing Load Facility, the Customer’s prorated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

“OEB” means the Ontario Energy Board.

“OEB-Approved Connection Procedures” means Hydro One’s connection procedures as approved by the OEB from time to time.

“Ontario Energy Board Act” means the *Ontario Energy Board Act* being Schedule “B” of the *Energy Competition Act*, S.O. 1998, c. 15, as amended.

“Pool-Funded Cost” means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

“Premium Costs” means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short timeframe for delivery; and the difference between having Hydro One’s employees, agents and contractors perform work on overtime as opposed to during normal business hours.

“Rate Order” has the meaning ascribed thereto in the *Transmission System Code*.

“Ready for Service Date” means the date upon which the Hydro One Connection Work is fully and

completely constructed, installed, commissioned and energised to the Connection Point. The Customer’s disconnect switches must be commissioned prior to this date in order to use them as isolation points.

“Standard Terms and Conditions” means these Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects including this Appendix “A” attached hereto.

“Surety Bond Requirements” means a surety bond that meets all the following requirements:

- (a) is in a form that is satisfactory to Hydro One;
- (b) surety must be Canadian;
- (c) surety must be financially acceptable to Hydro One must have at, a minimum, a long-term credit rating of “A” from a bond-rating agency acceptable to Hydro One;
- (d) provides that fees, charges and commissions associated with the surety bond, including drawings therefrom, are payable by the Customer;
- (e) allows for presentment in Toronto, Ontario or presentment using a valid fax number where the surety does not have a branch in Toronto, Ontario;
- (f) has an expiry date that is acceptable to Hydro One;
- (g) provides that any notice that the surety does not wish to extend the surety bond for any additional period of expiry must be provided, in writing, to Hydro One Networks Inc., 483 Bay Street, 7th Floor, South Tower, Toronto, Ontario M5G 2P5 Attn: Treasurer at least 60 days prior to any expiration date;
- (h) permit partial drawings and multiple presentations;
- (i) provide that drawings will be paid without the surety enquiring whether Hydro One has a right as between itself and the Customer to make such demand, and without recognizing any claim of the said Customer;
- (j) only requirement to be met in order to draw on the surety bond is that Hydro One present a certificate certifying that the amount demanded is payable to Hydro One by the Customer pursuant to the terms of the Connection Cost Recovery Agreement made between the Customer and Hydro One, as it may be amended by the Customer and Hydro One from time to time;
- (k) will be governed by the laws of the Province of Ontario and the laws of Canada applicable therein; and

- (l) any dispute or claim shall be submitted to the exclusive courts within the jurisdiction of the Province of Ontario.

Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"Transformation Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code*.

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code*.

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of

Connection Cost Estimate Agreement (Connection of Hydro Rd MTS)

Hydro Ottawa Limited (the "**Customer**") has requested and Hydro One Networks Inc. ("**Hydro One**") has agreed to perform the Work as defined in the Scope of Work attached hereto (as Schedule "A"), to determine the estimated cost of the Proposed Project (defined below) and to undertake the Work under the Standard Study Agreement Terms and Conditions v. 6 (August 2024) attached hereto as Schedule "B", Schedule "A" and Schedule "B" both forming a part hereof (the "**Agreement**").

I. Proposed Project

The Customer is proposing to build and connect Hydro Rd MTS (the "**Customer's Facilities**") to Hydro One's Merivale TS to Hawthorne TS 230kV circuits M30A and M31A about [REDACTED] from Hydro One's Hawthorne TS (the "**Proposed Project**").

II. Information Requirements

The Customer shall provide Hydro One with the following:

1. site location map(s) with suitable details of Hydro Rd MTS location within the property, station layout diagram showing location of line entrance structures;
2. single line diagrams of Hydro Rd MTS showing all major equipment at 230kV and 44kV;
3. technical descriptions of the operating philosophy of the electrical equipment, and the protection and control philosophy of the Customer's Facilities (including any proposed Customer Facilities related to the Proposed Project) that could affect Hydro One's transmission system; and
4. a completed Impact Assessment Application for a System Impact Assessment to be performed by the IESO (available at www.ieso.ca) and a completed application for a Customer Impact Assessment to be performed by Hydro One.

III. Completion Date:

Hydro One shall complete the Work by no later than **two hundred and ten (210) Business Days** after the latest of:

- (a) the Customer executing this Agreement;
- (b) the Customer providing the information described above under the heading "Information Requirements";
- (c) where applicable, where the Customer has applied for a System Impact Assessment ("**SIA**") to be performed by the IESO, the Customer providing Hydro One with a copy of the SIA for the Proposed Project **OR** where Hydro One has applied for a SIA, Hydro One receiving the results of the SIA from the IESO; and
- (d) the Customer paying Hydro One the amount specified below in subsection V(a) under the heading "Costs".

IV. Impact of Subsequent Changes to the Information Provided by Customer or to the System Impact Assessment

If:

- (a) the Customer makes any changes to the information provided by the Customer as described above under the heading "Information Requirements" after Hydro One has commenced the Work; or

(b) where applicable, the IESO makes any changes to the System Impact Assessment (“SIA”) for the Project;

and any of the changes in (a) or (b) above:

- (i) results in an increase in the cost of Hydro One performing the Work, then, notwithstanding the payments contemplated below under the heading “Costs”, the Customer shall make such further payment(s) as may be required by Hydro One in the time specified by Hydro One; and
- (ii) otherwise affects any other provision of this Agreement, including (but not limited to) the time required for completion of the Work, the parties shall negotiate and agree upon the required amendments to this Agreement, and Hydro One shall be under no obligation to resume performance of the Work until such time as the parties agree in writing on such amendments.

V. Costs

- (a) The Customer shall pay Hydro One’s Actual Cost of performing the Work. Hydro One estimates that the Actual Cost of performing the Work will be \$750,000 plus HST in the amount of \$97,500 which amount (including HST) the Customer shall pay Hydro One on the execution of this Agreement by the Customer (the “**Advance Payment**”). Hydro One shall apply the Advance Payment towards the Actual Cost of performing the Work.
- (b) Within 90 days after the completion of the Work, Hydro One shall provide the Customer with a final invoice or credit memorandum showing whether the Advance Payment exceeds or is less than the Actual Cost of performing the Work. Within 30 days after the said final invoice or credit memorandum is rendered by Hydro One, any difference between the Actual Cost (plus applicable Taxes) and Advance Payment shall be paid by Hydro One to the Customer (if the Advance Payment exceeds the Actual Cost plus applicable Taxes), or by the Customer to Hydro One (if the Advance Payment is less than the Actual Cost plus applicable Taxes).

VI. HST Registration Information

The HST registration number for Hydro One is [REDACTED]. The HST registration number for the Customer is [REDACTED].

VII. No Commitment to Back Feed and Ready for Service Dates for the Proposed Project Until CCRA Execution

The Customer acknowledges and agrees that Hydro One cannot agree to be bound to a ready for service date or a back feed date for the Proposed Project until such time as Hydro One and the Customer have executed a Connection and Cost Recovery Agreement (CCRA) for the Proposed Project.

VIII. Purchase Order

This Agreement will supersede the terms of any purchase orders issued by the Customer to Hydro One in respect of the Project irrespective of whether same have been issued by the Customer and/or accepted by Hydro One on or after the execution of this Agreement by the Customer.



IX. Term

Except as expressly set out in this Agreement, this Agreement shall be in full force and effect and binding on the parties upon the date that this Agreement was executed by Hydro One and shall expire on the date that is after the latest of:

- (a) Hydro One performing all of the Work; and
- (b) the Customer paying all amounts required to be paid by the Customer under the terms of this Agreement.

Termination of this Agreement for any reason shall not affect the liabilities of either party that were incurred or arose under this Agreement prior to the time of termination. Termination of this Agreement for any reason shall be without prejudice to the right of the terminating Party to pursue all legal and equitable remedies that may be available to it including, but not limited to, injunctive relief.

X. Counterparts

This Agreement may be executed by the parties in writing or via electronic signatures and in one or more in counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be delivered via fax, electronic mail (in portable document format) or other transmission method and any counterpart so delivered is deemed to have been duly and validly delivered and be valid and effective for all purposes.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the Execution Date written below.

HYDRO ONE NETWORKS INC.

Signed by:

Robert Reinmuller
24DC60889B73411...

Robert Reinmuller, P.Eng.
VP, Transmission System Planning & Large Customer

Execution Date: April 3, 2025

I have the authority to bind the Corporation

HYDRO OTTAWA LIMITED

DocuSigned by:

Laurie Heuff
7E34070D87DA4FF...

Name: Laurie Heuff Vice President, Distribution System Planning and Asset Management

Title: ~~2025-03-28~~

DocuSigned by:

Steve Hawthorne
3FFDCAB677014DC...

Name: Steve Hawthorne Director, Distribution Program Delivery

Title: ~~2025-03-31~~

Date:

I/We have the authority to bind the Corporation

SCHEDULE “A”: Scope of Work - Connection Estimates

Hydro One will work with the Customer to develop planning specifications for Hydro One’s use in preparation for developing estimates for the Proposed Project (“**Planning Specifications**”). The Planning Specifications may also identify the work that Hydro One requires the Customer to perform in respect of the Proposed Project.

Hydro One will prepare and provide the Customer with an estimate consistent with the Association for the Advancement of Cost Engineering (“**AACE**”)’s Class 3 +30%/-20% for the work that will be outlined in the Planning Specifications as work that is to be performed by Hydro One (the “**Estimate**”). For greater certainty, the Estimate:

- will include the cost and the required work plan and schedule for Hydro One to perform the work necessary in respect of the Proposed Project, including, but not limited to:
 - Building line tap from 230kV circuits M30A and M31A to the Customer’s line entrance structure
 - Review and identify modification to M30A and M31A protection settings at terminal stations (Hawthorne TS and Merivale TS) and Albion TS. Including the following (please refer to the protection impact assessment provided to the IESO for the SIA):
 - Installation of Main and Alt CTM equipment
 - Transfer trip (A and B) sending from Hawthorne TS to Customer station to trip 230kV associated breaker.
 - Receive at Hawthorne TS breaker fail redundant transfer trip sent from Customer station.
 - Coordinate with the line back-up function at Customer station 230kV side.
- real estate requirements and potential impact on landowners, environmental assessments and approvals, and regulatory approvals.
- will not include any estimate of the cost of the work that Hydro One identifies in the Planning
- Specifications as work that Customer must perform in respect of the Proposed Project.s
 - Customer will build and own the station.
 - Customer is responsible to obtain all permits required for the station.
 - Refer to the protection impact assessment provided to the IESO for SIA for protection and control requirements. The below provides high level Customer requirements:
 - Build suitable tele-protection links between Customer station and Hawthorne TS (Customer confirmed fiber will be used).
 - Provide redundant fiber links (Main and Alt) for ‘A’ and ‘B’ teleprotection channels to Hawthorne TS.
 - Customer station shall communicate to ISOC/OGCC via Customer’s owned ICCP link.
 - Implement transfer trip received from M30A and M31A TT (A and B), sent from Hawthorne TS and trip into the associated 230kV circuit breaker.
 - Install Breaker Fail (BF) protection on the 230kV circuit breakers. BF protection should send redundant (A and B) TT to Hydro One’s Hawthorne TS
 - Coordinate with the line back-up function at Customer station 230kV side.

The schedule for performing the work outlined in the specifications will assume that the parties will enter into a CCRA by no later than the date that will be specified in the estimate. If the CCRA is not executed by such date, the required work plan, schedule and cost estimate will require revision.

The abovementioned activities, to be performed by Hydro One, shall be herein referred to as “**Work**”. At the request of the Customer, this Agreement is being executed and Hydro One is commencing to perform the Work in advance of the SIA being performed by the IESO and in advance of Hydro One performing a Customer Impact Assessment (“**CIA**”) which Hydro One normally commences after the IESO has performed the SIA for the Project. The CIA and the SIA must be performed for the Project under the Transmission System Code. As such, the Customer is assuming that any additional requirements identified by the IESO in the SIA and/or in the CIA reports will not be included in the Estimate and all or a portion of same may need to be re-performed by Hydro One at the Customer’s expense

SCHEDULE B – Standard Study Agreement Terms and Conditions

1. Definitions

In the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

“Actual Cost” means Hydro One’s charge for equipment, labour and materials at Hydro One’s standard rates plus Hydro One’s standard overheads and interest thereon.

“Applicable Laws” means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission, board, court or agency.

“Business Day” means a day that is not a Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto are not open for business during normal banking hours.

“Code” or “Transmission System Code” means the *Transmission System Code*, the code of standards and requirements originally issued by the OEB on July 14, 2000 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

“Confidential Information” has the meaning ascribed thereto in the Connection Agreement.

“Connection Agreement” means the form of connection agreement appended to the Transmission System Code as Appendix 1, Version A where the Customer is a load customer and Version B where the Customer is a generator (as that term is defined in the Transmission System Code). Notwithstanding the foregoing, if the Customer has a transmission connection agreement that has been modified in the manner described in Section 2 of Schedule 2 of Hydro One’s OEB-issued transmission licence ET-2003-0035 (the **“Hydro One Licence”**) to reflect the amendments described in Schedule 3 [for legacy system configurations as well as operating concerns for Bruce Power and OPG generation facilities] and/or Schedule 4 [to facilitate compliance with Power Reactor Operating Licences, issued by the Canadian Nuclear Safety Commission] of Hydro One’s transmission licence ET-2003-0035; or has entered in the transmission connection agreement described in Section 3 of Schedule 2 of Hydro One’s licence, any reference to Connection Agreement in this Agreement shall mean the Customer’s executed transmission connection agreement with Hydro One.

“Customer’s Facilities” has the meaning set forth in the *Code*, and includes, but is not limited to any new, modified or replaced Customer’s Facilities.

“IESO” means the Independent Electricity System Operator.

“Good Utility Practice” has the meaning set forth in the *Code*.

“Lender” means a bank or other entity whose principal business is that of a financial institution.

“OEB” means the Ontario Energy Board.

“OEB-Approved Connection Procedures” means Hydro One’s connection procedures as approved by the OEB from time to time.

“Person” shall include individuals, trusts, partnerships, firms and corporation or any other legal entity.

“Representative” means (i) a person controlling or controlled by or under common control of a party and each of the respective directors, officers, employees and independent contractors of a party and such party’s Representative, (ii) any consultants, agents or legal, financial or professional advisors of a party or such party’s Representative and (iii) in the case of Customer, any institution providing or considering providing financing for the Proposed Project, including such institution’s directors, officers, employees and independent contractors or its consultants, agents or legal, financial or professional advisors.

“Taxes” means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than Taxes imposed upon income, payroll or capital).

“Work” means the work to be conducted in accordance with the Scope of Work attached to the Agreement as Schedule “A”.

2. Representations and Warranties

Each party represents and warrants to the other that:

- (a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
- (b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
- (c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or

other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any material contracts or instruments to which it is bound; or any laws applicable to it;

- (d) any individual executing the Agreement, and any document in connection herewith, on its' behalf has been duly authorized by it to execute the Agreement and has the full power and authority to bind it;
- (e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
- (f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada); and
- (g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

3. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and in compliance with all Applicable Laws.

4. Except as provided herein, Hydro One makes no representation or warranty, express, implied, statutory or otherwise, including, but not limited to, any representation or warranty as to the merchantability or fitness of the Work or any part thereof for a particular purpose.

5. Customer Covenants

The Customer acknowledges and agrees that:

- (a) Hydro One has informed the Customer that the OEB-Approved Connection Procedures apply to the Proposed Project;
- (b) Hydro One has informed the Customer that should the Proposed Project proceed, an agreement must be executed by the Customer and Hydro One to address the terms and conditions (which may include terms with respect to capital contributions required to be made) of Hydro One performing the work required in order to provide for the connection of the Customer's Facilities prior to Hydro One initiating any modifications to Hydro One's facilities or purchasing any equipment;
- (c) the Customer will be responsible for ensuring that the Proposed Project complies with all Applicable Laws;

(d) if the Customer is a Generator Customer (as that term is defined in the *Code*), the Customer is responsible for:

- i. providing the IESO with the modeling and studies to show the acceptable dynamic behavior of the generators as specified in the IESO System Impact Assessment; and
- ii. any resulting requirements that come from the IESO's review of dynamic studies that were or are not part of the IESO's System Impact Assessment including, but not limited to changes required to be made to the Work as a consequence of such review;

(e) the Customer shall obtain all applicable approvals required by the IESO for the connection of the Proposed Project;

(f) all right, title and interest, including copyright ownership, to all information and material of any kind whatsoever (including, but not limited to the work product developed as part of the Work) that may be developed, conceived and/or produced by Hydro One during the performance of the Agreement is the property of Hydro One, and the Customer shall not do any act that may compromise or diminish Hydro One's interest as aforesaid;

(g) if the Work involves Hydro One preparing a Customer Impact Assessment, the Customer consents, notwithstanding any term to the contrary in the Agreement, to Hydro One releasing the completed Customer Impact Assessment Report to be prepared by Hydro One to the IESO, the Ontario Electrical Safety Authority and customers connected to Hydro One's transmission system in the vicinity of the Proposed Project that may be affected by the Proposed Project;

(h) if the Work involves Hydro One preparing a Customer Impact Assessment, it may provide a deposit to the IESO for the IESO studies in relation to the Proposed Project. In the event that the IESO refunds part of the deposit to Hydro One, Hydro One will refund such funds to the Customer within 30 days of receipt by Hydro One. In the event that the IESO studies cost more than the deposit, the Customer agrees that it will pay the additional costs of such studies as invoiced to Hydro One by the IESO; and

(i) Hydro One performs the Work based on the known and anticipated system conditions at the time the Work is performed, should there be any changes to system conditions, including, anticipated system conditions, between the time

that Hydro One completes the Work and when the Customer proposes to connect the Proposed Project, the Work may have to be revised at the Customer's expense at that time.

6. Liability and Force Majeure

PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) of the Connection Agreement ("**Part III**") and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of the Agreement. Unless the context otherwise requires, all references in Part III to "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 6, the parties agree that the references to:

- (i) the Transmitter in lines 3 and 4 of Section 15.1 of Part III means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
- (ii) the Customer in lines 3 and 4 of Section 15.2 of Part III means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

This Section 6 shall survive the termination of the Agreement.

7. Events of Default

7.1 Each of the following events shall constitute an "Event of Default" under the Agreement:

- (a) failure by the Customer to pay any amount due under the Agreement;
- (b) breach by the Customer or Hydro One of any term, condition or covenant of the Agreement; or
- (c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

7.2 Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Subsection 7.1(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 15 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 15 calendar day

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period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the sum of the amounts payable by the Customer less any amounts already paid by the Customer under the terms of the Agreement.

7.3 Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Subsection 7.1(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 15 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 15 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

7.4 All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

8. Confidential Information

PART SEVEN: EXCHANGE AND CONFIDENTIALITY OF INFORMATION ("**Part 7**") and Sections 1.1.3 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of this Agreement. Unless the context otherwise requires, all references in Part 7 to "this Agreement" shall be deemed to be a reference to this Agreement.

9. Transmission Bypass

If the Project involves the installation of a Generation Facility by the Customer at the site of a load facility that is connected to or is connecting to the transmission system, the Customer acknowledges that Hydro One has informed the Customer that:

- (a) other than in the circumstances described in Section 11.2.3A of the Code, Hydro One is required

to collect bypass compensation (calculated in accordance with Section 11.2.6 of the Code) from the Customer under Section 11.2.1(b) of the Code if the Customer, while retaining its connection to Hydro One's transmission system, also connects its load facility to a Generation Facility such that the Customer reduces its load served directly by Hydro One's transmission system, and the line connection or transformation connection rates in relation to that facility will be reduced; and

(b) if the Generation Facility has an installed capacity of 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation and is being installed to displace all or any portion of the load demand at the load facility, the amounts invoiced by the IESO for line and transformation connection services applicable to the load facility will be calculated such that the customer demand in any hour will be the sum of: (a) the load-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by a Generation Facility in accordance with Note 3 of the Provincial Transmission Rates set out in the OEB-approved Uniform Transmission Rates (OEB-2021-0276)).

10. Assignment for Financing Purposes

(a) The Customer may, without the written consent of Hydro One, assign by way of security only all or any part of its rights or obligations under the Agreement to a Lender(s). The Customer shall promptly notify Hydro One, in writing, upon making such assignment.

(b) The Customer may disclose Confidential Information of Hydro One to a Lender or prospective Lender provided that the Customer has taken all precautions as may be reasonable and necessary to prevent unauthorized use or disclosure of Hydro One's Confidential Information by a Lender or prospective Lender.

(c) Where a notice of an Event of Default has been served on the Customer under Section 7.2, an agent or trustee for and on behalf of the Lender(s) ("**Security Trustee**") or a receiver appointed by the Security Trustee ("**Receiver**") shall upon notice to Hydro One be entitled (but not obligated) to exercise all of the rights and obligations of the Customer under the Agreement and shall be entitled to remedy the default specified in the notice of default within the cure period referred to in Section 7.2. Hydro One agrees to accept performance of the Customer's obligations under the Agreement by the Security Trustee or Receiver in lieu of the Customer's performance of such obligations, and will not exercise any right to terminate the Agreement due to an event of default if the Security Trustee, its nominee or transferee, or the Receiver acknowledges in

writing its intention to be bound by the terms of the Agreement by notifying Hydro One, and such acknowledgment is received within 20 days of the date of receipt by the Customer of the notice of default.

(d) the Lender will have no obligation or liability under the Agreement by reason of the assignment until such time as the Lender, the Security Trustee or the Receiver exercises any of the rights or obligations of the Customer under the Agreement.

(e) The Customer shall be deemed to hold the provisions of this Section 10 that are for the benefit of Lender(s) in trust for such Lender(s) as third party beneficiary(ies) under the Agreement.

11. Code and OEB-approved Transmission Connection Procedures

This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

- (a) *Transmission System Code*, the said provision shall be deemed to be amended so as to comply with the *Transmission System Code*; or
- (b) OEB-Approved Connection Procedures, the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures.

12. General

(a) Subject to Section 11, any amendment to the Agreement shall be made in writing and duly executed by both parties.

(b) Unless otherwise specified, references in the Agreement to Sections or Schedules are to sections, articles and Schedules of the Agreement. Any reference in the Agreement to any statute, regulation, any OEB-approved documents or any section thereof will, unless otherwise expressly stated, be deemed to be a reference to such statute, regulation, document or section as amended, restated or re-enacted from time to time. The insertion of headings is for convenience only, and shall not affect the interpretation of the Agreement. Unless the context requires otherwise, words importing the singular include the plural and vice versa. The words "including" or "includes" means including (or includes) without limitation.

(c) The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the

Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

- (d) Other than in accordance with Section 10 above, the Agreement may not be assigned without the written consent of the other party, which consent will not be unreasonably withheld.
- (e) The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.
- (f) Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.
- (g) The obligation to pay any amount due and payable hereunder shall survive the termination of the Agreement.

Feasibility Study Agreement - Cyrville MTS - 230kV Supply

Hydro Ottawa Limited (the "**Customer**") has requested and Hydro One Networks Inc. ("**Hydro One**") has agreed to perform the Work as defined in the Scope of Work attached hereto (as Schedule "A"), to determine the feasibility of the Proposed Project (defined below) and undertake the Work under the Standard Study Agreement Terms and Conditions v. 6 (August 2024) attached hereto as Schedule "B", Schedule "A" and Schedule "B" both forming a part hereof (the "**Agreement**").

I. Proposed Project

The Customer is proposing to connect a 230kV/27.6kV transformer station named Cyrville MTS (the "**Customer's Facilities**") to Hydro One's transmission system at 230kV circuit D5A and the upcoming A25, with a tap location approximately [REDACTED] from Hawthorne TS which requires the construction of an approximately [REDACTED] double circuit 230kV line to connect to the Customer's Facilities (collectively the "**Proposed Project**").

II. Information Requirements

The Customer shall provide Hydro One with the following:

- site location map(s) with suitable details of the major equipment (line entrance structure), high level staging plan for upgrade of the Customer Facility, line routing and the proposed connection to Hydro One's facilities;

III. Completion Date:

Hydro One shall complete the Work by no later than one hundred and sixty five (165) Business Days after the latest of:

- (a) the Customer executing this Agreement;
- (b) the Customer providing the information described above under the heading "Information Requirements"; and
- (c) the Customer paying Hydro One the Advance Payment specified below in subsection V(a) under the heading "Costs".

IV. Impact of Subsequent Changes to the Information Provided by Customer

If the Customer makes any changes to the information provided by the Customer as described above under the heading "Information Requirements" after Hydro One has commenced the Work, which;

- (i) results in an increase in the cost of Hydro One performing the Work, then, notwithstanding the payments contemplated below under the heading "Costs", the Customer shall make such further payment(s) as may be required by Hydro One in the time specified by Hydro One; and/or
- (ii) otherwise affects any other provision of this Agreement, including (but not limited to) the time required for completion of the Work, the parties shall negotiate and agree upon the required amendments to this Agreement.

Hydro One shall be under no obligation to resume performance of the Work until such time as the parties agree in writing on such amendments and/or the Customer make such further payment(s) as may be required by Hydro One in the time specified by Hydro One.

V. Costs

- (a) The Customer shall pay Hydro One's Actual Cost of performing the Work. Hydro One estimates that the Actual Cost of performing the Work will be \$350,000 plus HST in the amount of \$45,500 which amount (including HST) is \$395,500. The Customer shall pay Hydro One on the execution of this Agreement by the Customer (the "**Advance Payment**"). Hydro One shall apply the Advance Payment towards the Actual Cost of performing the Work.

- (b) Within 90 days after the completion of the Work, Hydro One shall provide the Customer with a final invoice or credit memorandum showing whether Advance Payment exceeds or is less than the Actual Cost of performing the Work. Within 30 days after the said final invoice or credit memorandum is rendered by Hydro One, any difference between the Actual Cost (plus applicable Taxes) and the Advance Payment shall be paid by Hydro One to the Customer (if the amount already paid by the Customer exceeds the Actual Cost plus applicable Taxes), or by the Customer to Hydro One (if the Advance Payment is less than the Actual Cost plus applicable Taxes).

VI. HST Registration Information

The HST registration number for Hydro One is [REDACTED] and the HST registration for the Customer is [REDACTED]

VII. No Commitment to Back Feed and Ready for Service Dates for the Proposed Project until CCRA Execution

The Customer acknowledges and agrees that Hydro One cannot agree to be bound to a ready for service date or a back feed date for the Proposed Project until such time as Hydro One and the Customer have executed a Connection and Cost Recovery Agreement (CCRA) for the Proposed Project.

VIII. Purchase Order

This Agreement will supersede the terms of any purchase orders issued by the Customer to Hydro One in respect of the Proposed Project irrespective of whether same have been issued by the Customer and/or accepted by Hydro One on or after the execution of this Agreement by the Customer.

IX. Term

Except as expressly set out in this Agreement, this Agreement shall be in full force and effect and binding on the parties upon the date that this Agreement was executed by Hydro One and shall expire on the date that is after the latest of:

- (a) Hydro One performing all of the Work; and
- (b) the Customer paying all amounts required to be paid by the Customer under the terms of this Agreement.

Termination of this Agreement for any reason shall not affect the liabilities of either party that were incurred or arose under this Agreement prior to the time of termination. Termination of this Agreement for any reason shall be without prejudice to the right of the terminating Party to pursue all legal and equitable remedies that may be available to it including, but not limited to, injunctive relief.

[SECTION X. AND SIGNATURE PAGE FOLLOWS]

X. Counterparts

This Agreement may be executed by the parties in writing or via electronic signatures and in one or more in counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be delivered via fax, electronic mail (in portable document format) or other transmission method and any counterpart so delivered is deemed to have been duly and validly delivered and be valid and effective for all purposes.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the Execution Date written below.

HYDRO ONE NETWORKS INC.

Signed by:

Robert Reinmuller

24DC00000B79411...

Robert Reinmuller, P.Eng.
VP, Transmission System Planning & Large Customer

Execution Date: July 11, 2025

I have the authority to bind the Corporation

HYDRO OTTAWA LIMITED

Steve Hawthorne

Name:

Title:

DocuSigned by:

Steve Hawthorne

3FFDCAB677014DC...

Name: Director, Distribution Program Delivery

Title:

Date: 2025-07-02

I/We have the authority to bind the Corporation

SCHEDULE "A": Scope of Work - Feasibility

General Description

Hydro One will work with the Customer and/or the Customer's designated consultant to select and evaluate preferred transmission line routes, connection facility locations and preliminary technical solutions.

The work will include one or more of the following areas:

1. **Preferred Transmission Line Route (if required):** select and recommend preferred transmission routing based on preliminary loading requirements and cost estimates, evaluating real estate requirements and potential impact on landowners, environmental assessments and approvals, regulatory hearings and approvals required, public hearings and notice requirements.
2. **Preliminary Technical Solution:** Determine high level technical alternatives and costs for transmission line routes and connection facility being evaluated.
3. Provide AACE Class 5 +100/-50% estimate and high-level plan/schedule for the execution of the Proposed Project once its feasibility is determined.

(all of the above is hereinafter referred to as the "**Work**").

The Work performed in this Feasibility stage is intended to allow the Customer to select the preferred transmission line routing and connection facility location option.

SCHEDULE B – Standard Study Agreement Terms and Conditions

1. Definitions

In the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

“Actual Cost” means Hydro One’s charge for equipment, labour and materials at Hydro One’s standard rates plus Hydro One’s standard overheads and interest thereon.

“Applicable Laws” means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission, board, court or agency.

“Business Day” means a day that is not a Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto are not open for business during normal banking hours.

“Code” or “Transmission System Code” means the *Transmission System Code*, the code of standards and requirements originally issued by the OEB on July 14, 2000 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

“Confidential Information” has the meaning ascribed thereto in the Connection Agreement.

“Connection Agreement” means the form of connection agreement appended to the Transmission System Code as Appendix 1, Version A where the Customer is a load customer and Version B where the Customer is a generator (as that term is defined in the Transmission System Code). Notwithstanding the foregoing, if the Customer has a transmission connection agreement that has been modified in the manner described in Section 2 of Schedule 2 of Hydro One’s OEB-issued transmission licence ET-2003-0035 (the **“Hydro One Licence”**) to reflect the amendments described in Schedule 3 [for legacy system configurations as well as operating concerns for Bruce Power and OPG generation facilities] and/or Schedule 4 [to facilitate compliance with Power Reactor Operating Licences, issued by the Canadian Nuclear Safety Commission] of Hydro One’s transmission licence ET-2003-0035; or has entered in the transmission connection agreement described in Section 3 of Schedule 2 of Hydro One’s licence, any reference to Connection Agreement in this Agreement shall mean the Customer’s executed transmission connection agreement with Hydro One.

“Customer’s Facilities” has the meaning set forth in the *Code*, and includes, but is not limited to any new, modified or replaced Customer’s Facilities.

“IESO” means the Independent Electricity System Operator.

“Good Utility Practice” has the meaning set forth in the *Code*.

“Lender” means a bank or other entity whose principal business is that of a financial institution.

“OEB” means the Ontario Energy Board.

“OEB-Approved Connection Procedures” means Hydro One’s connection procedures as approved by the OEB from time to time.

“Person” shall include individuals, trusts, partnerships, firms and corporation or any other legal entity.

“Representative” means (i) a person controlling or controlled by or under common control of a party and each of the respective directors, officers, employees and independent contractors of a party and such party’s Representative, (ii) any consultants, agents or legal, financial or professional advisors of a party or such party’s Representative and (iii) in the case of Customer, any institution providing or considering providing financing for the Proposed Project, including such institution’s directors, officers, employees and independent contractors or its consultants, agents or legal, financial or professional advisors.

“Taxes” means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than Taxes imposed upon income, payroll or capital).

“Work” means the work to be conducted in accordance with the Scope of Work attached to the Agreement as Schedule “A”.

2. Representations and Warranties

Each party represents and warrants to the other that:

- (a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
- (b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;
- (c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or

other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any material contracts or instruments to which it is bound; or any laws applicable to it;

- (d) any individual executing the Agreement, and any document in connection herewith, on its' behalf has been duly authorized by it to execute the Agreement and has the full power and authority to bind it;
- (e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;
- (f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada); and
- (g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

3. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and in compliance with all Applicable Laws.

4. Except as provided herein, Hydro One makes no representation or warranty, express, implied, statutory or otherwise, including, but not limited to, any representation or warranty as to the merchantability or fitness of the Work or any part thereof for a particular purpose.

5. Customer Covenants

The Customer acknowledges and agrees that:

- (a) Hydro One has informed the Customer that the OEB-Approved Connection Procedures apply to the Proposed Project;
- (b) Hydro One has informed the Customer that should the Proposed Project proceed, an agreement must be executed by the Customer and Hydro One to address the terms and conditions (which may include terms with respect to capital contributions required to be made) of Hydro One performing the work required in order to provide for the connection of the Customer's Facilities prior to Hydro One initiating any modifications to Hydro One's facilities or purchasing any equipment;
- (c) the Customer will be responsible for ensuring that the Proposed Project complies with all Applicable Laws;

(d) if the Customer is a Generator Customer (as that term is defined in the *Code*), the Customer is responsible for:

- i. providing the IESO with the modeling and studies to show the acceptable dynamic behavior of the generators as specified in the IESO System Impact Assessment; and
- ii. any resulting requirements that come from the IESO's review of dynamic studies that were or are not part of the IESO's System Impact Assessment including, but not limited to changes required to be made to the Work as a consequence of such review;

(e) the Customer shall obtain all applicable approvals required by the IESO for the connection of the Proposed Project;

(f) all right, title and interest, including copyright ownership, to all information and material of any kind whatsoever (including, but not limited to the work product developed as part of the Work) that may be developed, conceived and/or produced by Hydro One during the performance of the Agreement is the property of Hydro One, and the Customer shall not do any act that may compromise or diminish Hydro One's interest as aforesaid;

(g) if the Work involves Hydro One preparing a Customer Impact Assessment, the Customer consents, notwithstanding any term to the contrary in the Agreement, to Hydro One releasing the completed Customer Impact Assessment Report to be prepared by Hydro One to the IESO, the Ontario Electrical Safety Authority and customers connected to Hydro One's transmission system in the vicinity of the Proposed Project that may be affected by the Proposed Project;

(h) if the Work involves Hydro One preparing a Customer Impact Assessment, it may provide a deposit to the IESO for the IESO studies in relation to the Proposed Project. In the event that the IESO refunds part of the deposit to Hydro One, Hydro One will refund such funds to the Customer within 30 days of receipt by Hydro One. In the event that the IESO studies cost more than the deposit, the Customer agrees that it will pay the additional costs of such studies as invoiced to Hydro One by the IESO; and

(i) Hydro One performs the Work based on the known and anticipated system conditions at the time the Work is performed, should there be any changes to system conditions, including, anticipated system conditions, between the time

that Hydro One completes the Work and when the Customer proposes to connect the Proposed Project, the Work may have to be revised at the Customer's expense at that time.

6. Liability and Force Majeure

PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) of the Connection Agreement ("**Part III**") and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of the Agreement. Unless the context otherwise requires, all references in Part III to "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 6, the parties agree that the references to:

- (i) the Transmitter in lines 3 and 4 of Section 15.1 of Part III means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
- (ii) the Customer in lines 3 and 4 of Section 15.2 of Part III means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

This Section 6 shall survive the termination of the Agreement.

7. Events of Default

7.1 Each of the following events shall constitute an "Event of Default" under the Agreement:

- (a) failure by the Customer to pay any amount due under the Agreement;
- (b) breach by the Customer or Hydro One of any term, condition or covenant of the Agreement; or
- (c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

7.2 Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Subsection 7.1(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 15 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 15 calendar day

v. 6 (August 2024)

period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the sum of the amounts payable by the Customer less any amounts already paid by the Customer under the terms of the Agreement.

7.3 Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Subsection 7.1(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 15 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 15 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

7.4 All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

8. Confidential Information

PART SEVEN: EXCHANGE AND CONFIDENTIALITY OF INFORMATION ("**Part 7**") and Sections 1.1.3 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into and form an integral part of this Agreement. Unless the context otherwise requires, all references in Part 7 to "this Agreement" shall be deemed to be a reference to this Agreement.

9. Transmission Bypass

If the Project involves the installation of a Generation Facility by the Customer at the site of a load facility that is connected to or is connecting to the transmission system, the Customer acknowledges that Hydro One has informed the Customer that:

- (a) other than in the circumstances described in Section 11.2.3A of the Code, Hydro One is required

to collect bypass compensation (calculated in accordance with Section 11.2.6 of the Code) from the Customer under Section 11.2.1(b) of the Code if the Customer, while retaining its connection to Hydro One's transmission system, also connects its load facility to a Generation Facility such that the Customer reduces its load served directly by Hydro One's transmission system, and the line connection or transformation connection rates in relation to that facility will be reduced; and

(b) if the Generation Facility has an installed capacity of 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation and is being installed to displace all or any portion of the load demand at the load facility, the amounts invoiced by the IESO for line and transformation connection services applicable to the load facility will be calculated such that the customer demand in any hour will be the sum of: (a) the load-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by a Generation Facility in accordance with Note 3 of the Provincial Transmission Rates set out in the OEB-approved Uniform Transmission Rates (OEB-2021-0276)).

10. Assignment for Financing Purposes

(a) The Customer may, without the written consent of Hydro One, assign by way of security only all or any part of its rights or obligations under the Agreement to a Lender(s). The Customer shall promptly notify Hydro One, in writing, upon making such assignment.

(b) The Customer may disclose Confidential Information of Hydro One to a Lender or prospective Lender provided that the Customer has taken all precautions as may be reasonable and necessary to prevent unauthorized use or disclosure of Hydro One's Confidential Information by a Lender or prospective Lender.

(c) Where a notice of an Event of Default has been served on the Customer under Section 7.2, an agent or trustee for and on behalf of the Lender(s) ("**Security Trustee**") or a receiver appointed by the Security Trustee ("**Receiver**") shall upon notice to Hydro One be entitled (but not obligated) to exercise all of the rights and obligations of the Customer under the Agreement and shall be entitled to remedy the default specified in the notice of default within the cure period referred to in Section 7.2. Hydro One agrees to accept performance of the Customer's obligations under the Agreement by the Security Trustee or Receiver in lieu of the Customer's performance of such obligations, and will not exercise any right to terminate the Agreement due to an event of default if the Security Trustee, its nominee or transferee, or the Receiver acknowledges in

writing its intention to be bound by the terms of the Agreement by notifying Hydro One, and such acknowledgment is received within 20 days of the date of receipt by the Customer of the notice of default.

(d) the Lender will have no obligation or liability under the Agreement by reason of the assignment until such time as the Lender, the Security Trustee or the Receiver exercises any of the rights or obligations of the Customer under the Agreement.

(e) The Customer shall be deemed to hold the provisions of this Section 10 that are for the benefit of Lender(s) in trust for such Lender(s) as third party beneficiary(ies) under the Agreement.

11. Code and OEB-approved Transmission Connection Procedures

This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

- (a) *Transmission System Code*, the said provision shall be deemed to be amended so as to comply with the *Transmission System Code*; or
- (b) OEB-Approved Connection Procedures, the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures.

12. General

(a) Subject to Section 11, any amendment to the Agreement shall be made in writing and duly executed by both parties.

(b) Unless otherwise specified, references in the Agreement to Sections or Schedules are to sections, articles and Schedules of the Agreement. Any reference in the Agreement to any statute, regulation, any OEB-approved documents or any section thereof will, unless otherwise expressly stated, be deemed to be a reference to such statute, regulation, document or section as amended, restated or re-enacted from time to time. The insertion of headings is for convenience only, and shall not affect the interpretation of the Agreement. Unless the context requires otherwise, words importing the singular include the plural and vice versa. The words "including" or "includes" means including (or includes) without limitation.

(c) The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the

Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

- (d) Other than in accordance with Section 10 above, the Agreement may not be assigned without the written consent of the other party, which consent will not be unreasonably withheld.
- (e) The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.
- (f) Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.
- (g) The obligation to pay any amount due and payable hereunder shall survive the termination of the Agreement.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-123

EVIDENCE REFERENCE:

Ref. 1: [Electricity Reporting & Record Keeping Requirements \(RRR\): Section 2.1.4.2.10 Major Event Response Reporting](#)

Ref. 2: [Electricity Reporting & Record Keeping Requirements \(RRR\): Section 2.1.4.2 System Reliability Indicators](#)

Preamble:

OEB staff have produced the following table based on RRR data.

Row Labels	Number of MED	Number of interruptions from MED	SAIFI from MED	SAIDI from MED
2015	1	30	0.181	0.396
2016	3	16	0.037	0.128
2017	3	78	0.092	0.401
2018	2	143	1.004	21.913
2019	1	47	0.202	0.405
2020	2	8	0.089	0.768
2021	4	10	0.049	0.1
2022	1	72	0.817	38.252
2023	1	176	0.55	5.787

QUESTION(S):

- a) Please verify the data shown in the table above is correct, or provide a revised table as required
- b) Please expand the table by providing data from 2005 – 2014 and 2024.
 - i) If data is not available for all requested years, please explain why.
- c) Please explain what method was used to identify MED, for each year reported.

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RESPONSE(S):

a) Hydro Ottawa has verified the referenced data and provides a revised table below. The revised table reflects the RRR data provided to OEB. The 'Number of Interruptions from MED,' 'SAIFI from MED' and 'SAIDI from MED' values are correct as shown. The 'Number of Major Event Days (MEDs)' value has been corrected to align with Hydro Ottawa's records, as it differed from the table provided by OEB staff.

Table A - Revised Table based on RRR data.

Row Labels	Number of MED	Number of interruptions from MED	SAIFI from MED	SAIDI from MED
2015	2	30	0.181	0.396
2016	1	16	0.037	0.128
2017	2	78	0.092	0.401
2018	3	143	1.004	21.913
2019	3	47	0.202	0.405
2020	2	8	0.089	0.768
2021	1	10	0.049	0.1
2022	3	72	0.817	38.252
2023	3	176	0.55	5.787

b) The requirement to report MED days to the OEB became effective May 3, 2016. Therefore, no data is available prior to that date.

c) As described in Section 4.4 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement, Hydro Ottawa utilizes the IEEE Standard 1366 approach to identify MEDs. The threshold for classifying an MED is determined annually based on the previous five years' daily SAIDI values.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **3-Staff-124**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / pp. 2-10 (pdf pp. 2-10)

8 Ref. 2: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / p. 24 (pdf p. 47)

9 Ref. 3: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / p. 26 (pdf p. 49)

10
11 **Preamble:**

12 Hydro Ottawa describes its load forecast methodology as a three-step data-driven process that
13 leverages monthly regression modeling. The load forecast is described as beginning with a baseline
14 revenue load forecast, then adjusted for the impact of past CDM programs and future eDSM
15 programs as well as the impact of electrification and large load requests.

16
17 Per the Itron consultant's report, Hydro Ottawa's sales forecast (including CDM, eDSM,
18 electrification, and large load requests) appears to be slightly downward trending or maintained at
19 the same levels from 2018 to 2023. But from 2024-2030, Hydro Ottawa's sales forecasts are
20 projected to increase.

21
22 **QUESTION(S):**

23
24 a) Please clarify if Hydro Ottawa intends to propose any Local eDSM programs (also known as
25 Stream 2 programs). If yes, please provide details on when Hydro Ottawa expects to file an
26 application and how the corresponding CDM/eDSM impacts are considered in the load forecast.

27 b) Hydro Ottawa has identified CDM/eDSM as an impact category considered. Please confirm if
28 Hydro Ottawa has accounted for the anticipated savings from its NWCSP and any other
29 eDSM/CDM programs Hydro Ottawa is proposing as part of its 2026-2030 application load
30 forecast.

- 1 c) Please clarify the main factors that are causing the increase in sales forecast trend from
2 2024-2030 as compared to the years prior. Please provide the supporting rationale and data,
3 including the source of information.
- 4 d) Please clarify if there have been any changes in Hydro Ottawa's methodology in how to account
5 for each of the three impact categories that are considered in its load forecast? If so, please
6 describe the changes and the extent to which the three impact categories affect load forecast
7 (e.g., 5% average annual growth attributed to a specific driver).
- 8 e) Please provide Table 3-2: CDM and eDSM Savings from Exhibit 3 / Tab 1/ Schedule 1 /
9 Attachment B in MS Excel format. Along with the forecast eDSM savings, please provide:
- 10 i) Detailed calculations in MS Excel, with all formulas intact, for how Hydro Ottawa
11 determined its estimated share of provincial-wide annual energy savings for the
12 2025-2029 period and from 2030-2035, and discuss any considerations given to the
13 certainty of these values.
- 14 ii) Specific references to Hydro Ottawa's estimated portion of centrally administered
15 programs' net energy and demand savings based on the IESO's Final Verified 2017
16 CDM Summary Report.
- 17 iii) Please discuss if more recent provincial summary totals were considered when
18 determining Hydro Ottawa's share of future provincial savings from centrally
19 administered programs.
- 20 f) Please clarify how the electrification and large load energy request values in Section 7.2, Tables
21 7 and 8 of Exhibit 3 / Tab 1 / Schedule 1 were derived. Are the values based on known or
22 anticipated requests? If anticipated, what is the basis on which the estimates are based?
23
24

25 **RESPONSE(S):**
26

- 27 a) Hydro Ottawa's Non-Wires Customer Solution Program should be considered a local eDSM
28 program. Additional details about the program and the associated funding request for future
29 "Stream 2" eDSM activities within the NWCSPP can be found in Section 9.2.2.1 and Section
30 9.2.4.3 of Schedule 2-5-4 - Asset Management Process as well as interrogatory response
31 2-Staff-67 c (iii). The impact of local eDSM programs within the Non-Wires Customer Solution

- 1 Program (NWCSP) have not been added to the load forecast because the NWCSP is intended
2 to build upon province-wide programs that are already accounted for through the eDSM
3 framework within our load forecast. Please refer to the Attachment 3-Staff-124 (A) - Annual
4 eDSM kWh Savings for more information.
5
- 6 b) Hydro Ottawa confirms that it has incorporated eDSM/CDM programs funded by the IESO in its
7 revenue load forecast. The associated savings associated with NWCSP have not been
8 accounted for in the load forecast. Please see part a) for more details.
9
- 10 c) Transportation (LDEVs) and building electrification assumptions are the reason for the
11 increasing sales forecast trend from 2024-2030. Tables 2-1 and 2-2 in the Itron report show the
12 baseline sales forecast, the forecast excluding transportation and building electrification
13 additions. These tables show 2024-2030 sales trends consistent with the 2018-2023 trends.
14
- 15 Sales for numerous classes show a downward trend, the exception being the residential class
16 where customer growth is outweighing declining use per customer to result in a slight growth in
17 residential sales. The average annual growth in total sales from the baseline forecast is -0.1%
18 from 2024-2030. Table A below shows the baseline total sales forecast.

1

Table A - Baseline Total Sales Forecast

Year	Total Sales (MWh)	Change
2018	7,367,770	
2019	7,244,140	(1.70%)
2020	7,039,402	(2.80%)
2021	7,109,694	1.00%
2022	7,206,964	1.40%
2023	7,240,548	0.50%
2024	7,330,822	1.20%
2025	7,383,992	0.70%
2026	7,372,528	(0.20%)
2027	7,356,428	(0.20%)
2028	7,361,028	0.10%
2029	7,322,742	(0.50%)
2030	7,301,622	(0.30%)
2018-23		(0.30%)
2024-30		(0.10%)

2

3

4 d) There was no change in Hydro Ottawa’s methodology used to account for each of the three
 5 impact categories that are considered in its revenue load forecast.

6

7 e) Table 3-2: CDM and eDSM Savings from Attachment 3-1-1(B) - Hydro Ottawa Long-Term
 8 Electric Energy and Demand Forecast has been provided as Attachment 3-Staff-124(A) -
 9 Annual eDSM kWh Savings in MS Excel format.

10

11 f) Tables 7 and 8 in Schedule 3-1-1 - Revenue Load and Customer Forecast includes incremental
 12 MWh and kW for both electric vehicle (EV) and commercial electrification. The EV forecast is
 13 based on anticipated EV penetration as detailed in Section 9 of Schedule 3-1-1 - Revenue Load
 14 and Customer Forecast. The commercial electrification MWh and kW included from anticipated

- 1 system expansion requests has been estimated based on initial load requests provided by the
- 2 customer.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **3-Staff-125**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / pp. 11, 32 (pdf pp. 34, 55)

8
9 **Preamble:**

10 The residential connections were forecasted using an economic variable that exhibited slowing
11 growth, as well as dummy variables that do not exhibit a growth trend over the time horizon. The
12 growth of the resulting residential customer connection forecast has slowed to 1.1% over the
13 2024-2030 period from 1.8% over the 2018-2023 period. The observed growth was at least 1.7% in
14 every year from 2020-2024.

15
16 **QUESTION(S):**

- 17
18 a) Please explain any reasons why Hydro Ottawa expects connection growth to fall over the
19 forecast period.
20 b) Please provide the derivation of the economic variable.
21 c) Please provide the customer connection count for all months known in 2024-2025.
22 d) Please provide details of subdivision customer additions observed over the 2019-2025 period,
23 and subdivision customer additions expected over the 2025-2030 period.

1

2 **RESPONSE(S):**

3 a) The forecast for residential customer growth is based on a monthly regression model. This
4 model uses a blended economic variable that has a very strong correlation ($r=0.99$) with the
5 number of customers. The slowdown in customer growth during the forecast period is due to a
6 projected slowdown in the blended economic variable. Additionally, as noted in Attachment
7 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast, "while population
8 growth is expected to be high in 2024 at 2.3%, it's forecasted to drop to 1.5% in 2025 and then
9 to 1.0% or less after 2026"¹. Historically, from 2020 to 2024, residential growth was higher than
10 normal. This was primarily due to a peak in multi-unit residential buildings switching from a
11 single bulk meter to individual meters. This retrofitting activity is now at its highest point, so its
12 impact on growth is expected to decrease going forward.

13

14 b) The derivation of the economic variable is provided in Attachment 3-Staff-125(A) - Economic
15 Variable Derivation Breakdown.

16

17 c) Hydro Ottawa has provided the Residential customer connection count for all months known in
18 2024 and 2025 in Table A and B below.

¹ Attachment 3-1-1(B) - Long term energy and demand forecast, Pg 6

1 **Table A - 2024 Monthly Residential Customer Count**

	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	June 2024	Jul 2024	Aug 2024	Sept 2024	Oct 2024	Nov 2024	Dec 2024
Residential	336,052	336,757	337,445	338,052	338,260	338,813	339,391	339,939	340,722	341,075	341,702	342,808

2
 3 **Table B - 2025 Monthly Residential Customer Count²**

	Jan 2025	Feb 2025	Mar 2025	Apr 2025	May 2025	June 2025
Residential	343,066	343,347	343,662	344,232	344,640	344,954

4
 5 d) For load forecast purposes, Hydro Ottawa does not track if new customers are part of a residential subdivision or segregate
 6 residential customers by subdivision. As a result no forecast of subdivision customers specifically have been forecasted in the
 7 2025-2030 period. Historical growth trends for residential subdivisions have been captured in the historical customer count.

² Preliminary values; subject to change through annual review during RRR process

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **3-Staff-126**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / pp. 34 (pdf pp. 57)

8
9 **Preamble:**

10 The GS < 50 connections were forecasted using a Yr24Plus variable, reflecting the period starting
11 in 2024 going forward, reflecting 171 fewer customers beginning in 2024.

12
13 **QUESTION(S):**

- 14
15 a) Please explain what happened in January 2024 to trigger the need for this variable.
16 b) Please explain why the reduction in customer connections is expected to persist through the
17 test period.
18 c) Please provide the customer connection count for all months known in 2024 and 2025.

19
20
21 **RESPONSE(S):**

22
23 Hydro Ottawa notes that change in monthly average count of GS < 50 from 2023 to 2024 is an
24 increase of 81.

- 25
26 a) The GS<50 class experienced a significant slowdown in connection growth in 2024. From
27 January to October 2024, on average only 2 new connections were added per month. This is
28 less than the 2018-2023 average of 12. Without the Yr24Plus binary variable, the model would
29 have over predicted connections in 2024.

- 1 b) In the absence of additional information, it is assumed that the reduced growth will continue.
- 2 Data from October 2024 through June 2025 confirms connections have not increased to prior
- 3 growth levels.
- 4
- 5 c) Refer to Attachment 3-Staff-126(A) - Monthly GS <50 Customer Counts.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **3-Staff-127**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / pp. 31-40 (pdf pp. 54-63)

8 Ref. 2: Exhibit 3 / Attachment 3-1-1

9
10 **Preamble:**

11 Customer Models are provided for Residential, GS < 50, GS < 1,500, and a connection model is
12 provided for streetlights.

13
14 **QUESTION(S):**

- 15
16 a) Please explain the derivation of the customer / connection forecasts for all remaining rate
17 classes.
18 b) Please provide number of connections expected by year and rate class based on discussions
19 with prospective customers.
20 c) Where expert judgement was used in forecasting, please identify the information considered by
21 the expert.
22 d) Please explain how the information used extends to 2030.

23
24 _____
25 **RESPONSE(S):**

- 26
27 a) The remaining rate classes are Large User, Unmetered Scattered Load (USL) and Sentinel
28 Lights. For the Large User class, the forecast baseline count was held constant with
29 adjustments made for anticipated rate reclassifications as result of the electrification and large
30 load forecast, see response to question b). The forecast for USL was calculated by applying its

1 historical growth trend. Conversely, a decreasing trend, based on historical data, was used to
2 determine the connection count for Sentinel Lights during the Bridge and Test years.

3

4 b) Hydro Ottawa incorporated anticipated Large Load request customers into the revenue load and
5 customer forecast based on discussions with these customers. These requests from current
6 customers result in forecast customer rate reclassification in the Test years. Table A details the
7 impact to customer forecasts for 2026-2030 for these prospective customers.

8

9 **Table A - 2026-2030 Impact on Customer Count as result of Prospective Customers**

	2026	2027	2028	2029	2030
General Service 50-1000 kW	0	0	0	0	0
General Service 1000-1500 kW	0	-1	-2	-2	-2
General Service 1500-5000 kW	0	-1	-1	-1	-1
Large User	1	2	3	4	4

10

11 c) The customer/connection forecasts for the classes not mentioned above are held constant at
12 their October 2024 levels and adjusted as described in response (a). These historical
13 customer/connection counts are not correlated with economic variables used in the residential
14 or GS<50 model.

15

16 d) See response (a).

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **3-Staff-128**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / pp. 31-36 (pdf pp. 54-59)

8
9 Preamble:

10 XHeat, XCool, and XOther explanatory variables are used in several rate classes.

11
12 **QUESTION(S):**

- 13
14 a) Please provide the composition of XOther variables (XOtherRes, XOtherGS50, XOtherGS1000,
15 XOtherGS1500)
16 b) Please provide the methodology for forecasting the XOther variables.
17 c) Please provide the derivation of the historic and forecast XOther variables.

18
19 _____
20 **RESPONSE(S):**

21
22 a) The XOther variables, and all model variables, can be found in the model output files found in
23 Attachment 3-1-1(C) - 2. Load Forecast Data - kWh. The SAE variables, including XOther, are
24 constructed variables capturing the impact of end-use saturations, efficiency, economics, and
25 weather.

26
27 Additional time would be needed for Itron to fully deconstruct the variables into each component
28 and replicate the calculations in Excel.

- 1 b) Please refer to Section 2.1 and 2.2 of the Itron report Attachment 3-1-1(B) - Hydro Ottawa
2 Long-Term Electric Energy and Demand Forecast for an explanation of SAE modeling approach
3 and methodology.
4
- 5 c) Please see response to question (a), additional time would be needed to fully deconstruct the
6 variables into each component and replicate the calculations in Excel.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **3-Staff-129**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / p. 31 (pdf p. 54)

8
9 **QUESTION(S):**

10
11 a) Please provide the reason for the lower load in 2015 and 2016 that necessitated the Yr15 and
12 Yr16 variables.

13
14 **RESPONSE(S):**

15
16 a) The Yr15 and Yr16 binaries are included in the residential average use model to enable the
17 model to more accurately predict the 2015 and 2016 values. These binaries were included in
18 the model used in the prior rate forecast filed in 2020. Historically, use per customer has been
19 declining, 2015 and 2016 were no exception. Although these years were not noticeably lower
20 than prior or succeeding years, given the model variables used, the model would have over
21 forecasted 2015 and 2016 if the binaries were not included.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **3-Staff-130**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 3 / Tab 1 / Schedule 1 / Attachment B / pp. 15, 33 (pdf pp. 38, 56)

8
9 **Preamble:**

10 Excluding 2020 and 2021, the GS < 50 energy forecast exhibited growth from 2019 to 2024. There
11 is no variable which would capture growth over time.

12
13 **QUESTION(S):**

- 14
15 a) As a scenario, please create a forecast which uses a trend variable that takes a value of 1 in
16 January 2013, increasing by 1 each month, and reaching a value of 216 in December 2030.
17 i) Please include all regression output and resulting forecast.

18
19
20 **RESPONSE(S):**

- 21
22 a) The GS<50 sales regression model has been created to include the requested trend variable.
23 The resulting modeling output can be found in tab ERR in Attachment 3-Staff-130(A) - GS <50
24 Sales Regression Model. The trend variable is positive and statistically significant with a
25 t-statistic of 2.0 but including the trend variable impacts the existing modeling coefficients, most
26 notably the CDM variable. Without the trend variable the CDM coefficient is -0.88, with the trend
27 variable the CDM coefficient is -2.5. The CDM variable is increasing to compensate for the free
28 trend. Because the CDM variable is held constant and future CDM subtracted outside of the
29 model, this compensation for the trend does not occur in the forecast. The resulting forecast is
30 not consistent with historical trends. Table A below shows the baseline GS<50 MWh forecast

1 with the trend, adjusted for future CDM. This is comparable to the values shown in Table 2-2 of
 2 Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

3
 4 **Table A - Baseline GS<50 MWh Forecast with the Trend, Adjusted for Future CDM**

Sales Forecast (MWh)		
Year	GS<50	Change
2018	727,991	
2019	724,601	(0.5)%
2020	667,394	(7.9)%
2021	680,717	2.0%
2022	728,927	7.1%
2023	731,845	0.4%
2024	746,567	2.0%
2025	739,692	(0.9)%
2026	754,902	2.1%
2027	768,022	1.7%
2028	783,925	2.1%
2029	795,480	1.5%
2030	808,215	1.6%
2018-2023		0.1%
2024-2030		1.3%

5
 6 i) All regression output and resulting forecast has been included in Attachment 3-Staff-130(A) -
 7 GS <50 Sales Regression Model.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-131**

4
5 **EVIDENCE REFERENCE:**

6
7 Extreme Weather

8 Ref. 1: Exhibit 4 / Tab 1 / schedule 1 / p. 1 (pdf p. 11)

9
10 **QUESTION(S):**

11
12 a) Reference 1 states that “Climate projections from the City of Ottawa, in partnership with the
13 National Capital Commission and Environment and Climate Change Canada, confirm that these
14 severe weather impacts are expected to intensify across the National Capital Region in the
15 coming decades.” Please provide the climate projections and sources of information that
16 support this statement.

17 b) Please explain in detail how Hydro Ottawa budgeted for additional cost increases for the OM&A
18 programs (i.e. Vegetation Management, Information Management and Technology, Engineering
19 & Design, and System Operations and 24/7 Maintenance) involved in the efforts to prepare for
20 and respond to projected severe weather events for the forecast period.

21 i) Please provide additional cost increases related to the extreme weather that are
22 embedded in each OM&A program in (b).

23
24

25 **RESPONSE(S):**

26
27 a) The statement “Climate projections from the City of Ottawa, in partnership with the National
28 Capital Commission and Environment and Climate Change Canada,” is based on a newspaper

1 article published in the Ottawa Citizen titled “Welcome to Ottawa, the weather alert capital of
2 Canada,” published on February 11, 2023¹.

3
4 The statement is supported by a report produced for Hydro Ottawa by Stantec Consultant.
5 Please refer to Attachment 4-Staff-131(A) - Distribution System Climate Risk Vulnerability
6 Assessment, Table 5 Summary of Potential Climatic Changes by Mid-Century in the Greater
7 Ottawa Region. The table highlights climate projections that are expected to increase in
8 frequency and intensity for climate parameters such as extreme heat, snow, ice storms, and
9 high winds.

10
11 Both the Ottawa Citizen article and Attachment 4-Staff-131(A) - Distribution System Climate
12 Risk Vulnerability Assessment have used similar data sources to arrive at the same
13 conclusions. Some of the data sources include IPCC Climate Projections and RCP8.5 Scenario,
14 and from Environment and Climate Change Canada data sets.

15
16 b) Hydro Ottawa does not specifically budget for responding to extreme weather events. However,
17 based on the lessons learned from the 2022 Derecho, Hydro Ottawa has budgeted for a number
18 of proactive and storm hardening measures to improve its preparedness for and response to
19 future severe weather events:

- 20 ● **Vegetation Management:** Increases in this program are related to the adoption of the
21 Overstory software solution to facilitate a shift to more proactive tree trimming and the
22 targeted removal of at-risk trees given the significant tree canopy in the service territory. This
23 is a direct measure to mitigate risk as outlined in Section 3.2 of Schedule 4-1-2 - Operations,
24 Maintenance and Administration Programs.
- 25 ● **System Operations & 24/7 Maintenance:** This program has budgeted for incremental
26 positions to enhance real-time system monitoring, improve outage response times, and
27 strengthen overall system resilience. These investments are essential for ensuring the safe,
28 reliable, and efficient management of the electrical distribution system during and after

¹ Ottawa Citizen, “Welcome to Ottawa the Weather Alert Capital of Canada” (February 11, 2023)
<https://ottawacitizen.com/feature/welcome-to-ottawa-the-weather-alert-capital-of-canada>

- 1 severe weather events. Refer to Section 3.7 of Schedule 4-1-2 - Operations, Maintenance
2 and Administration Programs for additional information.
- 3 ● **Engineering & Design:** This program has seen cost increases to support the hiring of
4 incremental positions for proactive planning and storm-hardening efforts. These positions
5 are focused on designing more resilient infrastructure and developing strategies to
6 future-proof the system against the impacts of climate change. Refer to Section 3.8 of
7 Schedule 4-1-2 - Operations, Maintenance and Administration Programs for additional
8 information.
 - 9 ● **Information Management and Technology:** Costs in this program have increased to
10 support the company's transition to cloud-based solutions, which improves system resilience
11 and mitigates the risk of disruptions to Hydro Ottawa's data center. This is a key
12 recommendation from Attachment 2-1-1(A) - May 2022 Derecho - After Storm Report. These
13 costs are primarily driven by annual software subscription fees and investments in
14 cybersecurity to protect critical infrastructure. See Section 3.14 of Schedule 4-1-2 -
15 Operations, Maintenance and Administration Programs for additional information.
- 16
- 17 i) As noted above, Hydro Ottawa does not categorize its budgets or associated
18 increases in OM&A expenditures specifically related to responding to extreme
19 weather events and therefore is unable to provide the specific cost increases
20 requested.



Distribution System Climate Risk and Vulnerability Assessment

Final Report

November 11, 2019

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DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

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DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

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DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Executive Summary

Over 330,000 residences and businesses in the City of Ottawa and the Village of Casselman depend on Hydro Ottawa Limited (Hydro Ottawa) to supply continuous and reliable electrical service. In recent years, notably in 2018, Hydro Ottawa distribution infrastructure has been subjected to particularly extreme weather events that caused severe damages to their system. These events resulted in widespread outages and costly recoveries. In an effort to maintain reliable service in the coming years, Hydro Ottawa has retained Stantec Consulting Ltd. to conduct a climate risk and vulnerability assessment (CRVA) and provide recommendations for adaptation and risk mitigation within their operation, design, and business functions to help protect their infrastructure, service delivery and occupational health and safety. This assessment generally follows the guidelines set in the Canadian Electricity Association's guide "Adapting to Climate Change, A Risk Management Guide for Utilities" and identifies climate-related risks that exposed infrastructure are expected to face moving forward. Of particular interest to Hydro Ottawa, are three significant weather events that occurred in 2018, including a freezing rain event in April, a heavy wind event in May, and a series of tornados that touched down in September in the Ottawa region.

This work and the associated adaptation plan (submitted under a separate cover) will help drive continuous improvement to Hydro Ottawa's Asset Management System and will highlight climate risks and recommended mitigation measures related to Hydro Ottawa's policies, operations and maintenance, design, and emergency response practices.

The scope of work for the Hydro Ottawa Distribution System CRVA includes the following:

- Review of available information and documents including Hydro Ottawa's Corporate Risk Management Plan, Asset Management Plans, and outage reports;
- Facilitation of a series of interviews with Hydro Ottawa staff to help identify which weather events have caused disruptions and or failures and pose issues for Hydro Ottawa assets and service;
- Assessment of past weather events and an analysis of available climate data for the region and its projection into the future using internationally accepted Intergovernmental Panel on Climate Change (IPCC) projection data;
- Forensic evaluation of climate conditions that led to the development of three damaging weather events that took place in 2018, as described above;
- Identification of vulnerable infrastructure associated with Hydro Ottawa's distribution network and other supporting infrastructure and services as well as the climatic or weather events that are expected to impact these infrastructure systems;
- Workshop with Hydro Ottawa staff to validate assumptions related to their system and to assist in the completion of the risk assessment by identifying the level of impact on an asset should the climate event unfold, creating the climate risk profile; and,
- Preparation of a climate risk and vulnerability assessment report.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

The CRVA evaluates the future climate impacts on Hydro Ottawa's electrical distribution system and supporting infrastructure and identifies the potential risks associated with future changes in climate and extreme weather events. The assessment identifies risks to the infrastructure, buildings or facilities due to extreme weather and climate uncertainty based on current climate and future climate projections in the region. Extreme weather events include, but are not limited to high wind events, freezing rain, temperature and precipitation extremes, as well as complex events (i.e. climate events that are driven by the interaction of multiple climate parameters).

The CRVA uses Engineers Canada's Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol – an assessment methodology that conforms to the International Organization for Standardization (ISO) 31000:2018 Risk Management Standard, to identify relevant climate parameters and infrastructure responses, set up the risk evaluation worksheet, and assign risk ratings to each response to relevant climate considerations. This assessment is compatible with Hydro Ottawa's Asset Management Risk Procedure (AMRP); the project team selected the following performance criteria from the AMRP to assess the impacts of climate events on the infrastructure.

Response Category	Description
Level of Service: System Accessibility	Risk or opportunity impacting the connection of load and energy resource facility customers.
Level of Service: Service Quality	Risk or opportunity impacting the delivery of electric power in a form which meets customer's needs.
Resource Efficiency	Risk or opportunity impacting the additional use of internal or external resources.
Asset Value: Financial	Risk or opportunity impacting the realization of value from assets through resulting financial expense.

The infrastructures relied upon by Hydro Ottawa to deliver its services are comprised of substations, communication systems, the smart grid (e.g., telemetry, sensors, SCADA, internet) metering, third party services, overhead and buried power distribution as well as the service personnel who maintain and upgrade the system components on a regular basis. These assets are the backbone of Hydro Ottawa and are the focus of this study in order to determine the effects of climate on the infrastructure. The report provides a detailed description of these assets. Another vital part of the infrastructure is the administrative buildings (including the System Office that provides real time management of the distribution system) that are operated by Hydro Ottawa which are utilized for office and field personnel alike. These buildings are mainly utilized for administrative tasks such as client management, planning, detailed design and dispatching field personnel as required. As part of their distribution infrastructure, Hydro Ottawa also has operational buildings which are mainly located within their substations. These buildings are utilized to house switchgear, controls, batteries, and other essential elements to ensure the safe and reliable power distribution to their clients.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Changes in climate translate into direct and indirect impacts to municipal services, critical public infrastructure, spaces and assets/facilities, and community networks. Climate risks and hazards can be associated with two types of climate or weather events analogous to “shock” vs. “stress”: (1) rare, extreme and rapid/sudden-onset extremes or “shock events” and (2) slow onset or “creeping” threats or “stress events”. Extreme events are factored into building codes and practices through the use of extreme value or return period climate probabilities. Alternatively, many of the slow onset or recurring climate events that can be expected to occur several times annually are important when maintaining the service life and durability of structures and are sometimes included in standards. Studies indicate that damages to infrastructure from extreme events tend to increase dramatically above critical climate thresholds, even though the extreme weather events associated with these damages may not be much more severe than the type of storm intensity that occurs regularly each year. Impacts of climate change on assets can include structural damage, the reduced service life of assets and their components, and increased stress to systems and operations. These impacts can, for example, result in higher repair and maintenance costs, loss of asset value, strain resources and cause service interruptions.

The development of climate data for this climate vulnerability risk assessment of Hydro Ottawa’s distribution system involved three main activities:

- Identify climate parameters (e.g. temperature, precipitation, winds) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Project the probability of occurrence of climate hazards for future climate (i.e. 2050s); and,
- Convert projected probability of occurrence of future climate parameters into the five-point scoring scale used in Hydro Ottawa’s Asset Management System Risk Procedures.

The procedures used to perform this analysis, and the associated analytical results, are detailed in the report. Climate analyses in this study use projections for the “business-as-usual” Representative Concentration Pathway emissions scenario – RCP8.5 – and for the 2050s (2041-2070).

The climate parameters retained by the project team for this risk assessment and the projected future climate changes are presented in the table below.

Climate Parameter	Projected Climatic Changes by Mid-Century
Temperature – Extreme Heat	<ul style="list-style-type: none"> • Increased frequency and intensity • Increased frequency and length of heat waves
Temperature – Extreme Cold	<ul style="list-style-type: none"> • Decreased frequency and intensity • Occurrence of extreme cold outbreaks (“Polar Vortex” winters) likely to continue
Rain (Short Intensity – High Duration)	<ul style="list-style-type: none"> • Increased intensity of events • Reduced return periods (e.g. 20-yr return period event becoming a 10-yr return period event)
Freezing Rain & Ice Storms	<ul style="list-style-type: none"> • Increased frequency • Increased winter season (e.g. January) events
Snow	<ul style="list-style-type: none"> • Likely decrease in annual total accumulation • Continued occurrence and steady frequency of larger individual events



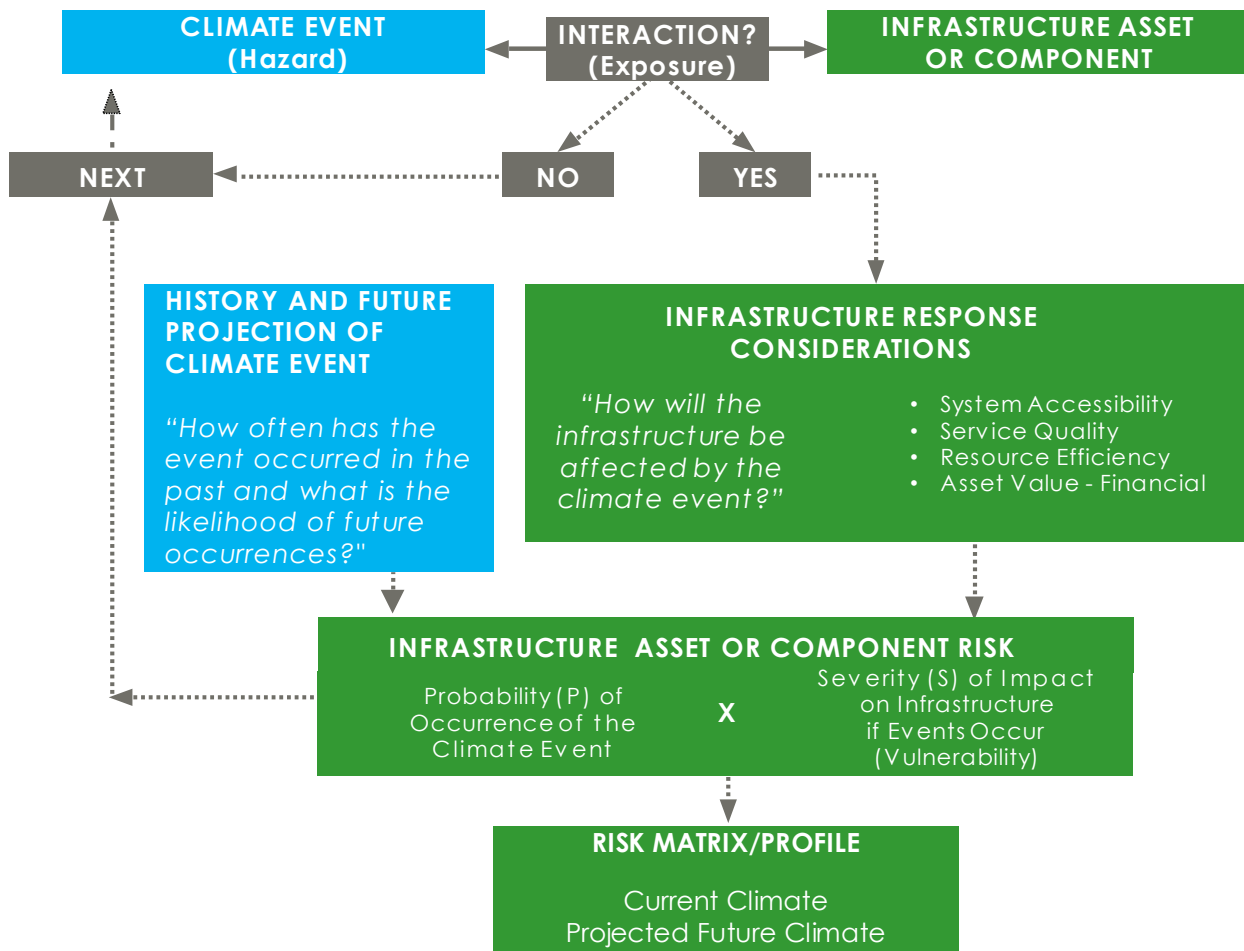
DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Climate Parameter	Projected Climatic Changes by Mid-Century
High Winds	<ul style="list-style-type: none"> Slight increase in frequency of high wind events (e.g. 90 km/hr; 120 km/hr)
Lightning	<ul style="list-style-type: none"> Increased frequency (by about 12% per degree Celsius of warming) Increased length of the higher frequency lightning season
Tornadoes	<ul style="list-style-type: none"> Increased frequency (25% increase by mid-century) Increase (near 2x) in number of severe thunderstorm days by mid-century (capable of possibly producing tornadoes, hail, extreme winds, and extreme rainfall events)
Fog	<ul style="list-style-type: none"> Likely increase
Frost (Freeze-Thaw Cycles)	<ul style="list-style-type: none"> Decrease in annual total number of freeze-thaw days Increase in monthly totals in the shoulder seasons (e.g. November and March)

The risk assessment followed the process illustrated next page.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT



In current climate conditions, very high risks were identified to power distribution lines and poles under extreme (> 120 km/h) wind conditions; these risks remain very high in future projected climate. Projected changes to climate in the Hydro Ottawa service area, under the RCP 8.5 GHG emissions scenario, are expected to increase risks to very high as follows:

- Daily maximum temperatures of 40°C or higher are expected to occur annually, impacting field staff; and,
- Freezing rain storms resulting in 40mm or more of ice accumulation are projected to occur more frequently in a 30-year period, resulting potentially in damage to a wide range of Hydro Ottawa's assets, disruptions in service, and impacts on staff.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

The report also provides the forensic analysis of three high-impact severe weather events as part of the overall scope of the PIEVC assessment. The forensic assessment was conducted by combining information on both infrastructure impacts and meteorological data, with the intent of establishing the following: event timelines (understanding the progression of events leading up to, during, and immediately following major outage events; meteorological/climate diagnosis (determine the type, extent, and severity of weather/climate event responsible for outages); and develop adaptation recommendations (determine actions that can be taken to assist in the preparation and response to similar events in the future - discussed in the Adaptation report under separate cover).

- April 15-16, 2018 – ice and wind storm: A combined wind and ice storm resulted in a total of 73,797 customers losing power during this event. Ottawa airport reported a total of 16 hours of freezing precipitation between noon EDT on April 15th and 10 AM EDT April 16th. The freezing rain and drizzle resulted in ice accumulations on overhead electrical infrastructure and adjacent vegetation exceeding 10 mm in total thickness, which was accompanied by strong winds gusting to 67 km/h on April 15 and 74 km/h on April 16. Total estimated ice accumulations by midnight on April 15th were likely around 10 mm, resulting in a small number of scattered power outages. However, between 7 AM and 2 PM on April 16th, the total number of outages increased from approximately 4,000 customers to over 43,000 customers.
- May 4, 2018 – wind storm: An intense low-pressure system tracked across a large portion of southern Ontario through to southern Quebec and adjacent areas of the United States, resulting in power outages for approximately 45,000 Hydro Ottawa customers. Damage reports, mainly consisting of large branches and individual trees being uprooted, were first confirmed in eastern Michigan in the Detroit area at 1:09 PM EDT. As the storm moved across southern Ontario, wind gusts approaching or exceeding 120 km/h were recorded at several locations. Widespread wind damage was reported across the Kitchener-Waterloo and Golden Horseshoe regions beginning after 3 pm EDT, including three fatalities attributed to the storm, as well as damage consisting of large branches and/or large trees snapped or uprooted, shingles and portions of roofs removed from homes and commercial buildings, and tens of thousands of electrical distribution customers in multiple jurisdictions losing power.
- September 21, 2018 – tornado outbreak: The September 21, 2018 tornado outbreak consisted of at least 7 separate tornadoes, with Hydro Ottawa's service area suffering impacts from the two strongest confirmed tornadoes within the outbreak, the long-tracked Kinburn-Dunrobin-Gatineau tornado, rated EF-3 on the 0 to 5 EF-scale of tornado intensity, and the Nepean-South Ottawa tornado, rated EF-2. The Kinburn-Dunrobin-Gatineau tornado formed at approximately 4:32 PM EDT, tracking roughly northeast until crossing the Ottawa River at approximately 4:52 PM EDT. Approximately one hour later, at 5:51 PM EDT, the Nepean tornado formed in association with a second line of storms. This tornado impacted the Merivale Transmission Station (TS) at almost exactly 6:00 PM EDT, resulting in a significant proportion of outages triggered in this event, and dissipated shortly after at approximately 6:09 PM EDT. All damage associated with these tornadoes, resulting in over 174,000 customers being affected, occurred in a time span of approximately 38 minutes.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Abbreviations

AMP	Asset Management Plan
AMRP	Asset Management Risk Procedure
CRMS	Corporate Risk Management System
CRVA	Climate Risk and Vulnerability Assessment
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
O&M	Operations and Maintenance
PIEVC	Public Infrastructure Engineering Vulnerability Committee
TGICA	IPCC Task Group on Data and Scenario Support for Impact and Climate Analysis
UWO	University of Western Ontario



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Introduction
November 11, 2019

1.0 INTRODUCTION

Over 330,000 residences and businesses in the City of Ottawa and the Village of Casselman depend on Hydro Ottawa Limited (Hydro Ottawa) to supply continuous and reliable electrical services. In recent years, notably in 2018, Hydro Ottawa distribution infrastructure has been subjected to particularly extreme weather events that caused severe damages to its electricity distribution system. These events resulted in widespread outages and costly recoveries. In an effort to secure reliable service in the coming years, Hydro Ottawa retained Stantec Consulting Ltd. to conduct a climate risk and vulnerability assessment (CRVA) and provide recommendations for risk mitigation and adaptation within their operation, design, and business functions to help protect their infrastructure, service delivery and occupational health and safety. This assessment generally follows the guidelines set in the Canadian Electricity Association's guide "Adapting to Climate Change, A Risk Management Guide for Utilities" and identifies climate-related risks that exposed infrastructure is expected to face moving forward. Hydro Ottawa also had a particular interest in assessing three significant weather events that occurred in 2018, including a freezing rain event in April, a heavy wind event in May, and a series of tornados that touched down in September in the Ottawa region.

This work and the associated adaptation plan (submitted under a separate cover) will help drive continuous improvement to Hydro Ottawa's Asset Management System and will highlight climate risks and recommended mitigation measures related to Hydro Ottawa's policies, operations and maintenance, design, and emergency response practices.

The scope of work for the Hydro Ottawa Distribution System CRVA includes the following:

- Review of available information and documents including Hydro Ottawa's Corporate Risk Management Plan, Asset Management Plans, and outage reports;
- Facilitation of a series of interviews with Hydro Ottawa staff to help identify which weather events have caused disruptions and or failures and pose issues for Hydro Ottawa assets and service;
- Assessment of past weather events and an analysis of available climate data for the region and its projection into the future using internationally accepted Intergovernmental Panel on Climate Change (IPCC) projection data;
- Forensic evaluation of climate conditions that led to the development of three damaging weather events that took place in 2018, as described above;
- Identification of vulnerable infrastructure associated with Hydro Ottawa's distribution network and other supporting infrastructure and services as well as the climatic or weather events that are expected to impact these infrastructure systems;
- Workshop with Hydro Ottawa staff to validate assumptions related to their system and to assist in the completion of the risk assessment by identifying the level of impact on an asset should the climate event unfold, creating the climate risk profile; and,
- Preparation of a climate risk and vulnerability assessment report.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Introduction
 November 11, 2019

This study considers the entire geographic extent of the Hydro Ottawa's service area which includes a vast portion of the City of Ottawa and the Village of Casselman, and includes both aboveground and underground electrical distribution assets. Hydro Ottawa's service territory is shown graphically in Figure 1.

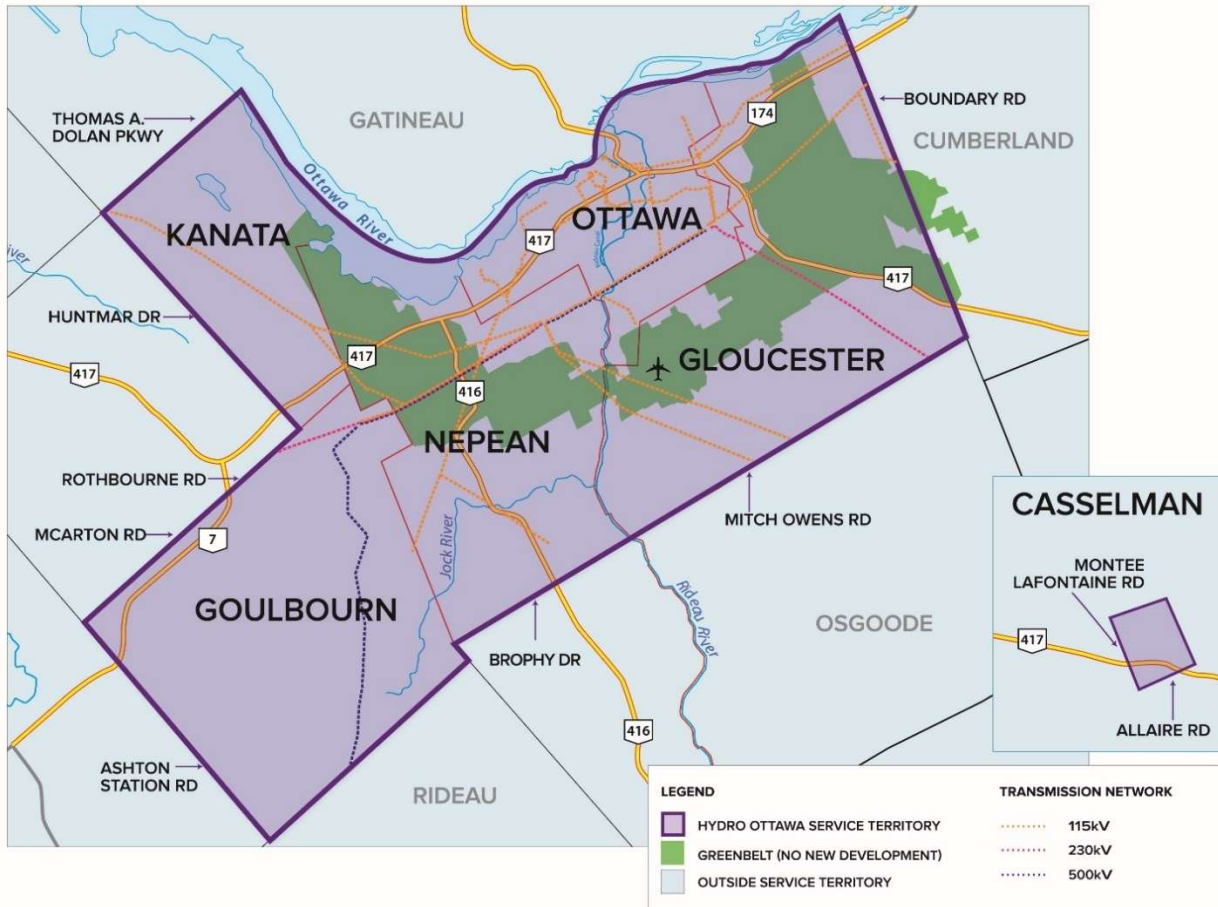


Figure 1 Map of Hydro Ottawa Service Territory¹

¹ Hydro Ottawa. 2018. <<https://hydroottawa.com/about/governance/overview>>



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Methodology
November 11, 2019

2.0 METHODOLOGY

This section outlines the methodology used to complete the climate risk and vulnerability assessment.

2.1 GENERAL

The CRVA evaluates the future climate impacts on Hydro Ottawa's electrical distribution system and supporting infrastructure and identifies the potential risks associated with future changes in climate and extreme weather events. The assessment identifies risks to the infrastructure, buildings or facilities due to extreme weather and climate uncertainty based on current climate and future climate projections in the region. Extreme weather events include, but are not limited to high wind events, freezing rain, temperature and precipitation extremes, as well as complex events (i.e. climate events that are driven by the interaction of multiple climate parameters).

The CRVA uses Engineers Canada's Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol – an assessment methodology that conforms to the International Organization for Standardization (ISO) 31000:2018 Risk Management Standard, to identify relevant climate parameters and infrastructure responses, set up the risk evaluation worksheet, and assign risk ratings to each response to relevant climate considerations. This assessment is compatible with Hydro Ottawa's Asset Management Risk Procedure (AMRP), the details of which are illustrated in **Figure 2**.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Methodology
 November 11, 2019

		Impact								
		Health, Safety & Environment	Safety							
		Health, Safety & Environment	Environment							
		Compliance	Compliance							
		Levels of Service	System Accessibility							
		Levels of Service	Service Quality							
		Levels of Service	Resource Efficiency							
		Levels of Service	Resource Efficiency							
		As set Value	Financial							
		As set Value	Financial							
		Corporate Citizenship	Corporate Brand							
		Corporate Citizenship	Corporate Brand							
Risks / Opportunities	Should the main risk or opportunity be classified as a Safety risk, PRO-MS-301.04 shall be evaluated through notifying the Manager, Occupational and Public Safety	N/A	Noncompliant with corporate regulation/policy	Load demand is exceeding planning limits	Noncompliant with municipal regulation	N/A	Load demand is exceeding thermal limits	N/A	Noncompliant with federal/provincial regulation	Unable to service new load
	Should the main risk or opportunity be classified as an Environmental risk, PRO-MS-301.04 shall be evaluated through notifying the Manager, Environment and CHSE Management System	N/A	N/A	N/A	Generation is exceeding planning limits	N/A	N/A	Generation is exceeding thermal limits	N/A	Unable to service new ERFs
	Service interruption resulting in <10,000 customer minutes interrupted	N/A	Service interruption resulting in >10,000 customer minutes interrupted	Service interruption resulting in <500,000 customer minutes interrupted	Service interruption resulting in >500,000 customer minutes interrupted	N/A	N/A	Service interruption resulting in >3,000,000 customer minutes interrupted	Service interruption resulting in >10,000,000 customer minutes interrupted	Service quality resulting in not meeting CSA standards
	Service quality resulting in customer complaint, but meets CSA standards	Requires <10 hours of overtime to complete O&M work or undergo training	Service quality resulting in customer escalation, but meets CSA standards	Requires >10 hours of overtime to complete O&M work or undergo training	Requires >250 hours of overtime to complete O&M work or undergo training	Requires >500 hours of overtime to complete O&M work or undergo training	Requires >1,500 hours of overtime to complete O&M work or undergo training	Requires >2,500 hours of overtime to complete O&M work or undergo training	Requires >5,000 hours of overtime to complete O&M work or undergo training	Unable to complete work with internal and/or external resources due to volume or skill gap
	Financial risk resulting in an O&M expense of <\$1k	Financial risk resulting in an O&M expense of <\$1k	Financial risk resulting in an O&M expense of >\$1k	Financial risk resulting in an O&M expense of >\$1k	Financial risk resulting in an O&M expense of >\$50k	Financial risk resulting in an O&M expense of >\$10k	Financial risk resulting in an O&M expense of >\$50k	Financial risk resulting in an O&M expense of >\$500k	Financial risk resulting in an O&M expense of >\$1M	Financial risk resulting in an O&M expense of >\$1M
	Financial risk resulting in a capital expense of <\$10k	Financial risk resulting in a capital expense of <\$10k	Financial risk resulting in a capital expense of >\$10k	Financial risk resulting in a capital expense of >\$10k	Financial risk resulting in a capital expense of >\$500k	Financial risk resulting in a capital expense of >\$10k	Financial risk resulting in a capital expense of >\$500k	Financial risk resulting in a capital expense of >\$5M	Financial risk resulting in a capital expense of >\$10M	Financial risk resulting in a capital expense of >\$10M
	N/A	N/A	Negative customer satisfaction survey results, while above comparators (remains local)	Negative customer satisfaction survey results, while above comparators	Negative customer satisfaction survey results, while below comparators	Negative customer satisfaction survey results, while below comparators	Negative customer satisfaction survey results, while below comparators	Negative publications at a provincial level	Negative publications at a national level	Negative publications at a national level
	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	1	Insignificant	4	Minor	9	Moderate	16	Extensive	25	Significant
	0	Rare	0	Minor	0	Moderate	0	Extensive	0	Significant
	2	Unlikely	8	Minor	18	Moderate	32	Extensive	50	Significant
	3	Possible	12	Minor	27	Moderate	48	Extensive	75	Significant
4	Likely	16	Minor	36	Moderate	64	Extensive	100	Significant	
5	Almost Certain	20	Minor	45	Moderate	80	Extensive	125	Significant	

Figure 2 Hydro Ottawa Asset Management Risk Procedure Matrix



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Methodology
November 11, 2019

A description of the PIEVC Protocol and discussions regarding the timescale of assessment and jurisdictional considerations are provided in the following subsections.

2.1.1 The PIEVC Protocol

The PIEVC Protocol (“Protocol”) is a risk assessment tool developed by Engineers Canada in 2008 and has since been applied to over 70 vulnerability risk assessments both within Canada and internationally. This risk assessment process involves the systematic review of historical climate information and the projection of the nature, severity and probability of future climate changes and events. This assessment of climatic changes is completed alongside an exposure assessment of infrastructure systems to these climate variables to determine whether or not there is an interaction between the climate event and the infrastructure components (Figure 3). The consequence of a particular damaging or disruptive climate event is then quantified by a severity score which ultimately informs the risk rating for a particular climate-infrastructure interaction. This process is reiterated for all applicable infrastructure elements to produce the full risk profile. Adaptation recommendations are then proposed to mitigate the consequence of the risk.

Furthermore, this process is extended to the future climate in order to see how the risk profile has changed with climate change. The Protocol is depicted as a flow chart in Figure 4; version VA 10.1 of June 2016 was used for this assessment.

This CRVA did not include the optional Step 4 – Engineering Analysis of the PIEVC Protocol (this step is recommended when the team needs a more in-depth analysis of the particular infrastructure-climate interaction where the team feels additional climate or engineering data is needed). The use of the Triple Bottom Line module was not part of this assignment, although risk mitigation and adaptation measures were developed and provided in a separate report.

The methodology of the Protocol includes five key steps to ensure the assessment is consistent and rigorous. The five key steps are:

1. Project Definition;
2. Data Gathering and Sufficiency;
3. Risk Assessment;
4. Engineering Analysis (optional as necessity and resources permit); and,
5. Recommendations and Conclusions.

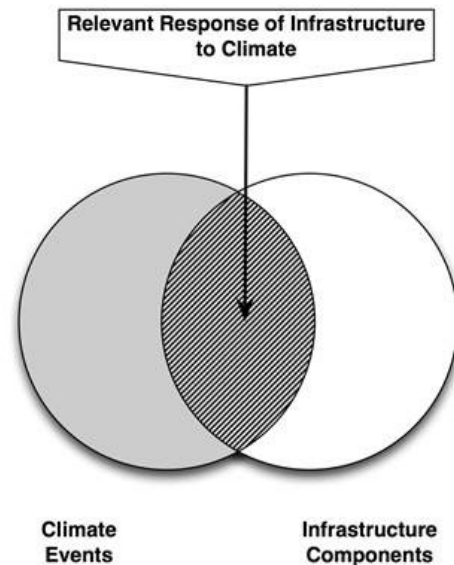


Figure 3 Diagram representing the interaction between climate events and infrastructure components



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The risk assessment identifies notable risks within Hydro Ottawa’s infrastructure system. ‘Moderate’, ‘High’, and ‘Very High’ risks are used to represent the distribution system’s risk profile. Risk mitigation and adaptation measures are recommended under a separate report for those risks identified to pose a significant threat to Hydro Ottawa’s operations and service provision.

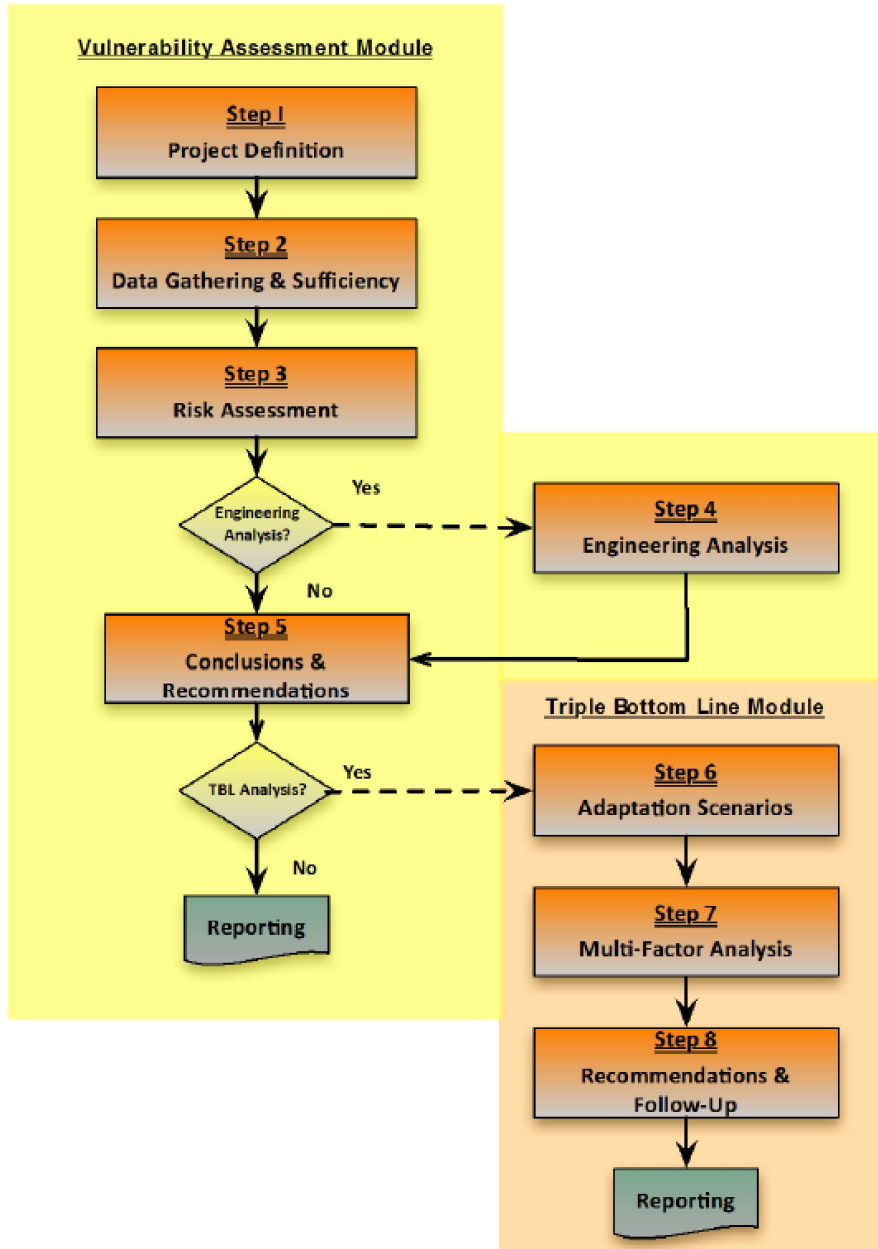


Figure 4 Flow Chart Illustrating the PIEVC Protocol Process



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2.1.2 Time Horizon

In addition to the current climate baseline (1981 to 2010), climate projections were produced for the 2020s (2011 to 2040), 2050s (2041 to 2070) and to 2080s (2071 to 2100) time horizons. For this assessment, based on the life-cycle of assets considered, future climate risks are evaluated for the 2050s time horizon.

2.2 PROJECT TEAM

A number of key experts played a role in this project, including risk, resilience, and adaptation expertise from Stantec and climatology expertise from Risk Sciences International (RSI). A list of the project team who contributed to this work is provided in Table 1.

Table 1 Summary of Project Team Members Who Contributed to This Work

Team Member	Role
Matthew McGrath	Hydro Ottawa, Project Manager
Greg Bell	Hydro Ottawa, Manager, Distribution Operations (Underground)
Ed Donkersteeg	Hydro Ottawa, Supervisor - Standards
Ben Hazlett	Hydro Ottawa, Manager, Distribution Policies and Standards
Nicole Flanagan	Stantec, Project Manager
Guy Félio	Stantec, Climate Change Resilience Advisor
Daniel Hegg	Stantec, Climate Change Adaptation Advisor
Riley Morris	Stantec, Environmental Engineer
Eric Lafleur, P.Eng.	Stantec, Senior Electrical Engineer
Heather Auld	RSI, Climatologist
Norman Shippee	RSI, Climatologist
Simon Eng	RSI, Climate Analyst
Katherine Pingree-Shippee	RSI, Climatologist

A list of interview participants is provided in Table 6 under **Section 5.1**.

2.3 SCHEDULE

This CRVA is part one of two components to a larger study, the second component being an assessment of risk mitigation and adaptation recommendations. The CRVA (part one) took place within a 5-month timeframe which generally followed the timeline presented in Table 2.



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Table 2 Generalized Risk Assessment Schedule

Project Tasks	Timeframe
Project Initiation	January 2019
Document review, data collection and initial analysis	January-March 2019
Interviews with Hydro Ottawa Stakeholders	March 2019
Risk assessment and analysis	March-May 2019
Risk assessment workshop with Hydro Ottawa Stakeholders	April 2019
Risk assessment review and report production	April-May 2019

2.4 LIMITATIONS

This climate risk and vulnerability assessment was completed using the best information available to the assessment team at the time of the study. The focus of the assessment presented in this report is on the existing electrical distribution system within the service territory of Hydro Ottawa, including areas within the City of Ottawa and the Village of Casselman. Due to the scale of Hydro Ottawa’s infrastructure system and the complexity of third-party interactions, this assessment represents a relatively high-level assessment of climate-related risks to Hydro Ottawa infrastructure where asset systems are grouped by function, impact and/or region.

The climate data and trends (current and future projections) used in this study were obtained through various sources (as described in **Section 4.1.1**) and analyses were carried out by Risk Sciences International’s climatology services. Cross-verification between climate information sources was conducted where possible to identify possible discrepancies between the data sources used.

Information regarding past system outages was provided by Hydro Ottawa and the identification of impacting historical weather and/or climate-related events was gathered and validated during interviews and a workshop with Hydro Ottawa stakeholders. Stantec did not conduct inspections or review incident reports to validate this information.



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3.0 INFRASTRUCTURE

This section outlines Hydro Ottawa's infrastructure, assets and third-party interactions that all work together and are the key elements to the company's success as a growing service provider.

3.1 GENERAL

Hydro Ottawa's electrical infrastructure is utilized to safely and reliably support the transformation and delivery of electricity to customers throughout the service territory which includes the Ottawa region and the village of Casselman. The services provided are an essential element to local residence, businesses and organizations that rely on the electricity for improved quality of life and economic growth.

The infrastructures relied upon to deliver these services are comprised of substations, communication systems, the smart grid (e.g., telemetry, sensors, SCADA, internet), metering, third party services, overhead and buried power distribution as well as the service personnel who maintain and upgrade the system components on a regular basis. These assets are the backbone of Hydro Ottawa and are the focus of this study in order to determine the effects of climate on the infrastructure.

Another vital part of the infrastructure are the administrative buildings (including the System Office that provides real time management of the distribution system) that are operated by Hydro Ottawa which are utilized for office and field personnel alike. These buildings are mainly utilized for administrative tasks such as client management, planning, detailed design and dispatching field personnel as required. It is vital to the success of the overall operations at Hydro Ottawa. As part of their distribution infrastructure, Hydro Ottawa also has operational buildings which are mainly located within their substations. These buildings are utilized to house switchgear, controls, batteries, and other essential elements to ensure the safe and reliable power distribution to their clients.

3.1.1 Sources of Information

In order to determine all the components and outline each individual asset at Hydro Ottawa's disposal, Stantec reviewed their Asset Management System Risk Procedure as well as the individual Asset Management Plans (AMP) for each asset.

3.1.2 Shared Assets and Third-Party Interactions

It is understood that shared assets and third-party interactions are required in order for Hydro Ottawa to be successful and continue to service their clients. In order to better understand each of them, please find below a small description on how they directly impact Hydro's infrastructure:



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1. Hydro One: provides main incoming power supply to Hydro Ottawa’s substations in various locations which include shared infrastructure and termination points;
2. The City of Ottawa and the village of Casselman: provides a drainage system through the city to limit rising water levels in hydro infrastructure as well as ensure proper road maintenance throughout all seasons;
3. Telecommunications Companies: provide telephone and fibre optic lines to various assets in order to allow communication from remote site; and,
4. Fuel Suppliers: allows for backup generators and fuel driven equipment to remain functional during normal operations and power outings.

3.2 INFRASTRUCTURE ELEMENTS

Table 3 below presents a list of infrastructure elements that were reviewed during the risk assessment as part of the information provided by Hydro Ottawa. Note that this list is a collapsed version to show the main pieces of equipment and not their individual components.

Table 3 List of Main Infrastructure Elements Considered in This Study

City of Ottawa	Village of Casselman
Buildings	Substations
Administrative and Operational Buildings	Buildings and Structural Components
Substation Buildings	P&C Buildings
Substations	Station Capacitor Voltage Transformers
Buildings and Structural Components	Station Circuit Breakers
Station Load Break Switch	Indoor Breakers
Station Capacitor Voltage Transformers	Core, Windings, Oil
Station Circuit Breakers	Station Metering
Station Power Transformers	Microprocessor Relays
Station Metering	Bar Conductors, Connections, Whips to Equipment
Station P&C Cabinets and Batteries (non-A/C spaces)	Power Distribution - Overhead (East-West Orientation)
Station Grounding and Ground Grid	Distribution Lines
Station Miscellaneous Equipment	Poles
Service and Personnel	Overhead Transformer
Service Vehicles	Overhead Load Breaker Switch
Service Equipment	Ground Connection
Staff and Occupational Health and Safety	Surge Arrestors
Communications, Smart Grid and Metering	Fused Cut Out
Hydro fiber	Power Distribution - Overhead (North-South Orientation)
Residential Metering	Distribution Lines



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City of Ottawa	Village of Casselman
Third Party Services and Interactions	Poles
Hydro One	Overhead Transformer
City of Ottawa	Overhead Load Breaker Switch
Telecommunications	Ground Connection
Fuel Supply	Surge Arrestors
Hydro Ottawa Subsidiaries	Fused Cut Out
Emergency Resources	Power Distribution - Underground
Old Subdivisions, Rural and Transmission	Civil Structures
Power Distribution - Overhead (East-West Orientation)	Underground Cables
Distribution Lines	Underground Primary Switchgear
Poles	Underground Transformers
Overhead Transformer	Power Distribution - Vaults
Ground Connection	Vault Transformers (Located in Third Party Buildings)
Surge Arrestors	
Fused Cut Out	
Power Distribution - Overhead (North-South Orientation)	
Distribution Lines	
Poles	
Overhead Transformer	
Ground Connection	
Surge Arrestors	
Fused Cut Out	
Power Distribution - Vaults	
Vault Transformers (Located in Third Party Buildings)	
New Subdivisions	
Power Distribution - Underground	
Civil Structures	
Underground Cables	
Underground Primary Switchgear	
Underground Transformers	
Power Distribution - Vaults	
Vault Transformers (Located in Third Party Buildings)	



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4.0 CLIMATE

This section will discuss the general climate profile for both current and future conditions within the Hydro Ottawa service territory and will describe climate parameters that will be considered in the risk assessment. Furthermore, a forensic evaluation of significant weather events from 2018 is provided at the end of this section. These items are discussed in more detail in the Climate Change Hazards Report, provided as **Appendix A** and is summarized, in part, in the following subsections.

4.1 GENERAL

Changes in climate translate into direct and indirect impacts to municipal services, critical public infrastructure, spaces and assets/facilities, and community networks. Climate risks and hazards can be associated with two types of climate or weather events analogous to “shock” vs. “stress”: (1) rare, extreme and rapid/sudden-onset extremes or “shock events” and (2) slow onset or “creeping” threats or “stress events”. Extreme events are factored into building codes and practices through the use of extreme value or return period climate probabilities. Alternatively, many of the slow onset or recurring climate events that can be expected to occur several times annually are important when maintaining the service life and durability of structures and are sometimes included in standards. Studies indicate that damages to infrastructure from extreme events tend to increase dramatically above critical climate thresholds, even though the extreme weather events associated with these damages may not be much more severe than the type of storm intensity that occurs regularly each year (Freeman and Warner, 2001; Coleman, 2003; Auld and MacIver, 2007; Auld, 2008). For instance, analyses of insurance loss data and other impact information, together with detailed analyses of extreme winds, indicate that losses to buildings in Southern Ontario are likely highly sensitive to increasing extreme wind speeds above threshold values. A detailed analysis of building damages and insurance claims within the City of Toronto and other Ontario municipalities indicate that damages and losses to buildings begin to increase significantly (nearly exponentially) when wind gusts exceed 90 km/hr (Auld, 2008).

Impacts of climate change on assets can include structural damage, the reduced service life of assets and their components, and increased stress to systems and operations. These impacts can, for example, result in higher repair and maintenance costs, loss of asset value, and interruption of services.

The development of climate data for this climate vulnerability risk assessment of Hydro Ottawa’s distribution system involved three main activities:

- Identify climate parameters (e.g. temperature, precipitation, winds) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Project the probability of occurrence of climate hazards for future climate (i.e. 2050s); and,
- Convert projected probability of occurrence of future climate parameters into the five-point scoring scale used in Hydro Ottawa’s Asset Management System Risk Procedures.



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following subsections, following an overview of the local climate of the Greater Ottawa Region. Additionally, forensic analyses of three high impact events in that impacted the Hydro Ottawa distribution system in 2018 are provided.

4.1.1 Sources of Information

Climate analyses in this study use projections for the “business-as-usual” Representative Concentration Pathway emissions scenario – RCP8.5 – and for the 2050s (2041-2700). Current greenhouse gas concentrations correspond to the RCP8.5 projected trajectory (Figure 5).

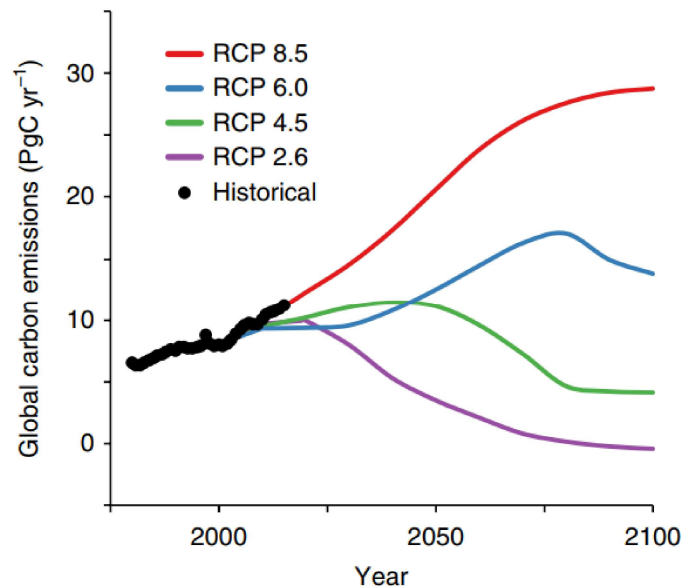


Figure 5 Historical CO₂ emissions for 1980-2017 and projected emissions trajectories until 2100 for the four Representative Concentration Pathway (RCP) scenarios. Current global emission trends have very closely followed the “business-as-usual” RCP8.5 scenario trajectory. Figure from Smith and Myers, 2018.

In this study, the “Delta Approach” is used to generate localized climate change projections (IPCC-TGICA, 2007). The Delta Approach method is one of the simplest and most straightforward approaches available for obtaining downscaled projections of future climate conditions. This approach consists in applying the average projected difference (the “delta”) for a given climate parameter to the historical average or baseline value. The Delta Approach generally provides more useful data when it is coupled with the use of many models (ensembles; e.g. CMIP5 GCMs) to generate projections than when coupled with a single or small set of models, regardless of model spatial and temporal resolution. A detailed description of the Delta Approach and how it is used in this assessment is provided in **Appendix A**.



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4.1.1.1 Specialized Studies

Some climate parameters are not well handled by climate modeling at any temporal or spatial resolution (e.g. severe and complex events such as ice storms and tornadoes). For these climate parameters, scientific literature is reviewed for any available guidance on the direction and magnitude of potential changes in these complex variables under a changing climate. The challenges posed in understanding future changes in complex events requires the application of detailed and time-consuming techniques to better reflect the scale and complexity of these hazards, and to increase confidence in analytical results. In these cases, projections were derived from applicable specialized studies available in the published literature, such as research addressing local changes in ice storm activity (Cheng et al., 2011) or high winds in the form of damaging wind gusts (Cheng et al, 2012; Cheng 2014).

In other cases, location-specific studies may not be available, but research into the potential effects of climate change on specific hazards can still provide guidance on future changes which can be applied to the study location. For example, ongoing research is refining our understanding of the links between air temperature and rainfall rates (Westra et al., 2014; Barbero et al., 2017), results of which can be used to develop tailored projections for the Greater Ottawa Region. Recent research on trends in tornado activity in the United States (Strader et al., 2017; Gensini and Brooks, 2018) also indicates both recent and future shifts in tornado occurrence which are potentially relevant to the Greater Ottawa Region and surrounding areas. These and other studies are an ongoing area of active investigation and RSI provides insight into these types of phenomena to the best of its ability. Climate hazards where specialized studies are applied in the calculation of future climate projections are identified within each section, and references to literature and studies are provided within the references section of the report.

4.1.1.2 Climate Analogue

Climate projections can also be used to identify a “climate analogue” for the Greater Ottawa Region. Climate analogues are simply geographical locations that currently exhibit average climate conditions that are similar to those projected for future time periods in the location of interest. Ideally, climate analogues currently have the same annual average temperature and precipitation values as the future projected climate for the Greater Ottawa Region, and also exhibit similar elevation and topography and exposure to atmospheric circulation patterns (e.g. lake and ocean influences). This method can inform the assessment in many ways, including evaluation of potential viable adaptation options which may be already in place at analogue locations (Ramírez-Villegas et al., 2011). In general, climate analogues can provide potential clues regarding new or emerging hazards which have not yet been experienced in the study location, offering a window into impacts and needed adaptation actions that could reasonably be anticipated under future conditions. They can also provide useful insights into hazards that are not well handled by climate modeling alone, especially when location and hazard specific studies are not readily available in the literature. For this study, a climate analogue location of Pittsburgh, Pennsylvania was identified for the Greater Ottawa Region. Pittsburgh, PA corresponds to the projected future annual average temperatures expected in the Greater Ottawa Region in the 2050s under the RCP8.5 scenario and has roughly similar city and elevation characteristics to those of Ottawa. This climate analogue provides general, “order of magnitude” comparisons which help further determine if climate change projections are in fact realistic and represent potentially “real” climates.



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4.1.1.3 Professional Judgment

“Perfect” or “ideal” information and data for given hazard usually do not exist, and assessments always require the application of professional judgement from interdisciplinary teams to make use of the data and information available. While sometimes referred to as a source of risk assessment information, professional judgement is better characterized as the process applied to the best available information; i.e., how is all available information weighted, interpreted, and applied within the assessment using the expertise of assessment team members. The PIEVC Protocol, for example, states that “Professional Judgment is the interpretation and synthesis of data, facts and observations collected by the team and the extrapolation of that analysis to provide a judgment of how the infrastructure may respond to a specific set of conditions.” (Engineers Canada, 2016). Within the context of an assessment, this refers to the use of professional judgement to interpret and apply what is often incomplete – but still the best available – data and information. The discussion and decision-making process surrounding the application of professional judgement is also documented in detail for the purposes of traceability, so that future review and application of any analytical results can be understood within the proper context.

4.1.2 Climate Parameters

The climate parameters and thresholds established for analysis in this study were assembled and analyzed through a combination of the following:

- Climatic design values in engineering codes and standards;
- Practitioner experience (especially in managing past impacts and risks);
- Literature review;
- Forensic investigation of past events; and,
- Stantec interviews with Hydro Ottawa personnel.

In some cases, multiple thresholds were developed for the same parameter, either because multiple thresholds held some significance for one or more of the assets in the Hydro Ottawa electrical distribution system, or because the threshold was different for each asset. Climate parameters and thresholds were then verified and refined, as needed, based on the experience and knowledge of Hydro Ottawa personnel at the 12 April 2019 workshop.

Identified climate hazards relevant to Hydro Ottawa’s electrical distribution system are outlined below in Table 4, ranging from short duration and sudden onset weather events (e.g. tornadoes) to gradual onset climate events (e.g. gradually increasing temperature extremes). Performance considerations and selection rationale are also outlined below.



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Table 4 List of Climate Parameters Considered in this Study

Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Temperature			
Extreme Heat	$T_{max} \geq 30^{\circ}\text{C}$	Level of Service – High heat days; danger to workers on site Resource Efficiency – Higher demand on grid for cooling; reduced time for cooling of electrical components	<p>$T_{max} \geq 30^{\circ}\text{C}$ identified as a personnel issue (associated with physical exertion and risk of heat exhaustion);</p> <p>T_{max} of 40°C used as a design value;</p> <p>Higher temperature thresholds lead to extra loading on the system from increased commercial and residential air conditioner use;</p> <p>Thermal stress can result in cracking and fissuring in materials (e.g. polymer-based materials).</p>
	$T_{max} \geq 35^{\circ}\text{C}$		
	$T_{max} \geq 40^{\circ}\text{C}$	Asset Value – High temperature operating threshold	
	$T_{mean} \geq 30^{\circ}\text{C}$	Level of Service – High heat days; danger to workers on site Resource Efficiency – Higher demand on grid; reduced time for cooling of electrical components	
Heat Waves	Consecutive Days with $T_{max} \geq 30^{\circ}\text{C}$ and $T_{min} \geq 23^{\circ}\text{C}$	Level of Service – Consecutive high heat days; danger to workers on site Resource Efficiency – Prolonged and (very) high demand (near capacity) on grid for cooling (nights not cooling); reduced time for cooling of electrical components	<p>System overloading common after 3 days of consecutive heat due to high demands on electrical grid (e.g. transformers) by increased air conditioning use;</p> <p>Equipment unable to cool properly reducing functionality.</p>
	Consecutive Days with $T_{max} \geq 30^{\circ}\text{C}$ and $T_{min} \geq 25^{\circ}\text{C}$		
Extreme Cold	$T_{min} \leq -35^{\circ}\text{C}$	Level of Service – Extreme cold days; danger to workers on site Resource Efficiency – Higher demand on grid for heating Asset Value – Approaching low temperature operating threshold	<p>Identified as a personnel issue;</p> <p>Older sections of Ottawa may experience overcapacity due to extensive use of electric baseboard heating;</p> <p>T_{min} of -40°C used as a design value;</p> <p>Extreme cold can result in underperformance of vehicles and outdoor infrastructure.</p>
Rain			
Extreme Rain	50 mm in 1 hour	Level of Service – Localized flooding; flooding of low-lying areas and subterranean infrastructure (e.g. underground vaults) possible	<p>Design threshold;</p> <p>Hydro Ottawa personnel have indicated extreme rainfall has not significantly impacts on Hydro Ottawa infrastructure, although low-lying equipment, such as vaults, may be more vulnerable (particularly in older neighbourhoods);</p> <p>Extreme rain can result in reduced accessibility to assets (e.g. flooded roadways).</p>



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Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Freezing Rain & Ice Storms			
Ice Accumulation	25 mm	Level of Service, Resource Efficiency – Local to regional power outages	Design threshold is 25 mm (corresponding to 12.5 mm of radial ice accretion on overhead lines); Most common damage to infrastructure related to ice accretion and accumulation on tree branches and resulting breaks; Combined ice accretion and wind is a concern.
	40+ mm	Asset Value, Level of Service, Resource Efficiency – Major and widespread outages possible; prolonged events	
Snow			
Snow Accumulation	Days with ≥ 5 cm	Level of Service – Snow clearing begins, could impact poles/infrastructure; salt use	Equipment issues mostly related to snow plow damage (transformer pads, transformers, and switchgear all potentially impacted); Issues with access to assets.
	Days with ≥ 10 cm	Level of Service – Snow clearing, could impact poles/infrastructure; salt use; access issues	
	Days with ≥ 30 cm	Level of Service – Snow clearing, could impact poles/infrastructure; salt use; access to lines and vaults; requires extra clearing	
High Winds			
Seasonal	60+ km/hr gust (Summer)	Level of Service – Lower wind speeds required to cause issues when trees have foliage; easterly winds are of particular concern	Hydro Ottawa personnel have noted wind intensity and frequency has increased in recent years; North-south power lines identified as vulnerable, particularly to prevailing winds; Potential damage to infrastructure due to tree and limb falls and wind-swept debris and reduced access due to debris deposits
	80+ km/hr gust (Winter)	Level of Service – Higher wind speeds result in issues when trees are bare; easterly winds are of particular concern	
Annual	90+ km/hr gust	Asset Value – Design threshold (corresponds to wind pressure values)	
	120+ km/hr gust	Asset Value – Wider spread of damage; straight line wind gusts	



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Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Lightning			
Lightning	Strikes near infrastructure	Level of Service – health and safety risk Resource Efficiency – direct strike could result in damage and loss of functionality	Hydro Ottawa personnel have noted thunderstorm duration and frequency are increasing; Lightning strikes may blow transformers, breakers, fuses, and arrestors (1-2 instances per year noted); Lightning protection system design frequency of 1 flash/km ² /yr; Some substations have lightning rods.
Tornadoes			
Tornadoes	EF1+ in Hydro Ottawa service area (City of Ottawa)	Asset Value, Level of Service, Resource Efficiency – Significant damage and major outages possible; prolonged events	Rare, but severe impacts to Hydro Ottawa infrastructure (e.g. 2018 tornado outbreak – damage due to tree and limb falls and flying debris, direct hit of Merivale transmission station, disruption of transportation corridors impacted response efforts).
	EF1+ point probability (i.e. tornado striking a specific asset, e.g. a substation, in the City of Ottawa service area)		
Invasive Species			
Emerald Ash Borer (EAB)	T _{min} ≤ -30°C	Asset Value – Damage to hydro poles and other vulnerable infrastructure	Hydro Ottawa personnel report increased damage to hydro poles by both EAB and the spike in woodpecker population following the introduction of EAB to the Greater Ottawa Region; EAB infestation makes trees vulnerable to breakage which can lead to damage to power lines; T _{min} ≤ -30°C is the kill threshold for EAB mature, non-feeding larvae.
Giant Hogweed	3 Days T _{max} ≤ -8°C	Level of Service – Significant human health risk upon exposure	Upon contact, a severe occupational hazard for workers – sap can cause serious skin inflammation on contact, exposure to sunlight results in more serious reaction (e.g. blisters, discolouration, scars), contact with eyes can result in loss of vision, blindness, or damage; 3 days with T _{max} ≤ -8°C required for germination of Giant Hogweed seeds.
Fog			
Fog	Days in Winter (Nov.-March)	Asset Value – Damage to hydro poles and other vulnerable infrastructure	Aerosolizing of salts can cause corrosion and moisture in winter; Salt spray on insulators and conductors can cause pole fires and flashovers.



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Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Frost			
Freeze-thaw Cycles	Daily T_{max} T_{min} temperature fluctuation around 0°C	<p>Asset Value – Freeze-thaw cycles can result in weathering and damage to hard infrastructure (minimum of 30 cycles/year required to damage concrete)</p> <p>Level of Service – Freeze-thaw cycles can lead to icy conditions which become a health and safety concern</p>	<p>Hydro Ottawa personnel have noted more mid-winter events, resulting in more pole fires;</p> <p>Freezing moisture known to cause failure in underground cabling, has increased incidents of pole fires, and limits access by crews;</p> <p>Associated thermal stresses and frost weathering can result in cracking and fissuring in materials (e.g. polymer-based materials);</p> <p>Large temperature ranges in freeze-thaw cycles can result in increased weathering and damage.</p>

4.2 CURRENT AND FUTURE CLIMATE PROFILE

As with the rest of globe, Canada, and Southern Ontario, the climate of the Greater Ottawa Region has been changing. Figure 6 presents the annual mean temperature in Ontario over the 1951-1980 and 1981-2010 periods. The change in mean annual temperature can be inferred from comparison of the plots (i.e. the difference in the coloration) with observed increases in temperature throughout the province, Southern Ontario, and in the Greater Ottawa Region. Using data collected at the Ottawa International Airport, observed annual daily mean, maximum, and minimum temperatures have risen over the 1981-2010 time period by 0.9°C, 1.0°C, and 0.8°C, respectively (**Figure 7** 1981-2010 Annual Mean, Maximum, and Minimum Temperature Data and Trends at Ottawa Airport

). The long observation record at the Ottawa Airport weather station (1939-present) further indicates the overall increase in temperature (OCCIAR, 2011). Furthermore, this long record highlights that the greatest temperature change has occurred during the winter months with an average mean increase of 2.2°C at the Ottawa Airport (OCCIAR, 2011) over the 1939-2010 time period. Of the three temperature variables (mean, maximum, and minimum), the greatest changes in a single season have been observed for the average winter minimum temperature over this long record, with an increase of 2.5°C at the Ottawa Airport (OCCIAR, 2011) during the 1939-2010 time period. The overall annual temperature trend for the Greater Ottawa Region appears to indicate an increase of 1.7°C per century (ECCC, 2016). Previous work in Ontario supports the increasing temperature trends and also suggests that certain areas within Southern Ontario could have summers that are 2-3°C warmer by the mid-century and potentially 4-5°C warmer by as early as 2071 (MNR, 2007).



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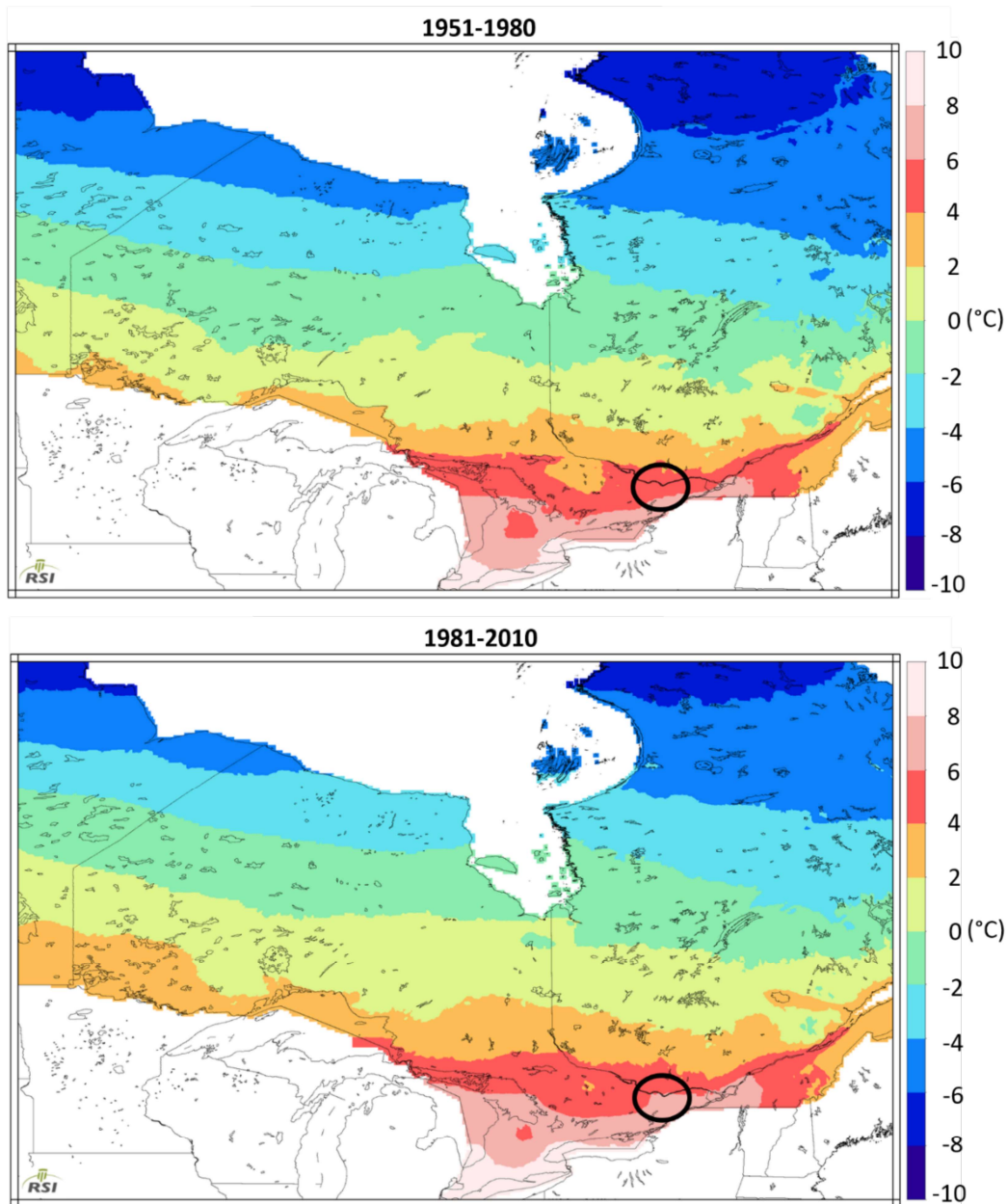


Figure 6 Observed annual mean (2m) air temperature over the 1951-1980 (upper) and 1981-2010 (lower) periods. The change in mean annual temperature can be inferred from comparison of the plots (i.e. the difference in the colouration), with observed increases in temperature throughout Southern Ontario. Annual mean temperatures in the Greater Ottawa Region (located within the black circle) have increased from 4-6°C during the 1951-1980 period to 6-8°C during the 1981-2010 period. (Data from ECCC/NRCan Canadian Gridded Temperature and Precipitation Data [CANGRD], 10 km horizontal resolution, using the ANUSPLIN climate modeling software [McKenney et al., 2011]; plots produced by Risk Sciences International.)



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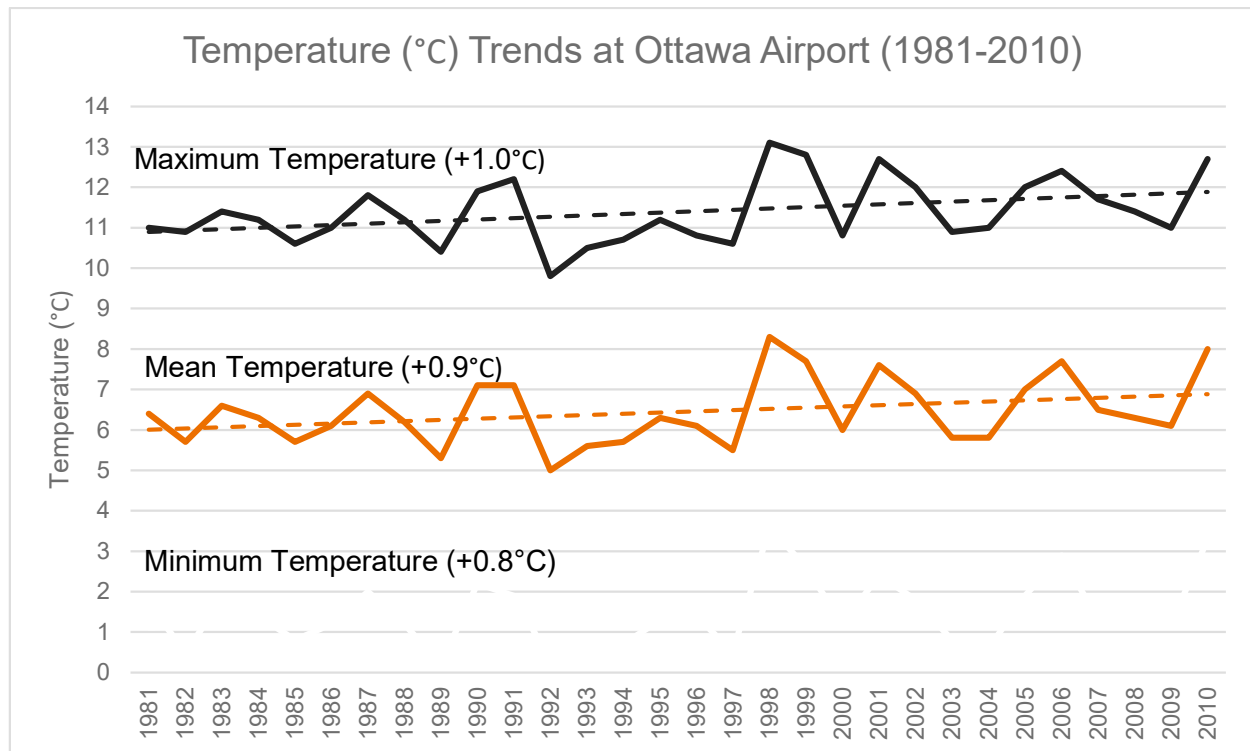


Figure 7 1981-2010 Annual Mean, Maximum, and Minimum Temperature Data and Trends at Ottawa Airport

The warming of the climate system has also led to important changes in temperature extremes. Since 1950, the number of cold days and nights has decreased while the number of warm days and nights has increased in Canada (Bush et al., 2014). As a result, a decrease in the frequency and intensity of extreme cold events has been observed in the Greater Ottawa Region. Nevertheless, extreme cold events still continue to occur in association with wintertime southward dips in the Polar Vortex, such as those in recent winters (2012-13, 2013-2014, 2017-18, and 2018-19). Alternatively, an increase in the frequency and intensity of extreme heat events has been observed. For instance, at the Ottawa Airport, the average annual number of days with a maximum temperature of 30°C or greater has increased from 13.4 days to 15 days over the 1981-2010 time period. Similarly, an increase in the frequency and duration of heat waves has also been observed in the region.

Precipitation trends in the region also appear to be changing, though less steadily than temperature. The Greater Ottawa Region has experienced an overall increase in observed total annual precipitation, with total precipitation increasing 25.9 mm at the Ottawa Airport during the 1981-2010 time period (Figure 8). The long observation record at Ottawa Airport further indicates an overall increase in total annual precipitation (+142 mm over the 1939-2010 time period) (OCCIAR, 2011). While this long-term increase in total annual precipitation is coupled with a long-term slight decrease in the annual winter precipitation (-9 mm over the 1939-2010 time period) (City of Ottawa, 2011; OCCIAR, 2011), average December-January-February rainfall total has increased at the Ottawa Airport from 69.1 mm to 80.6 mm during the 1981-2010 time period.



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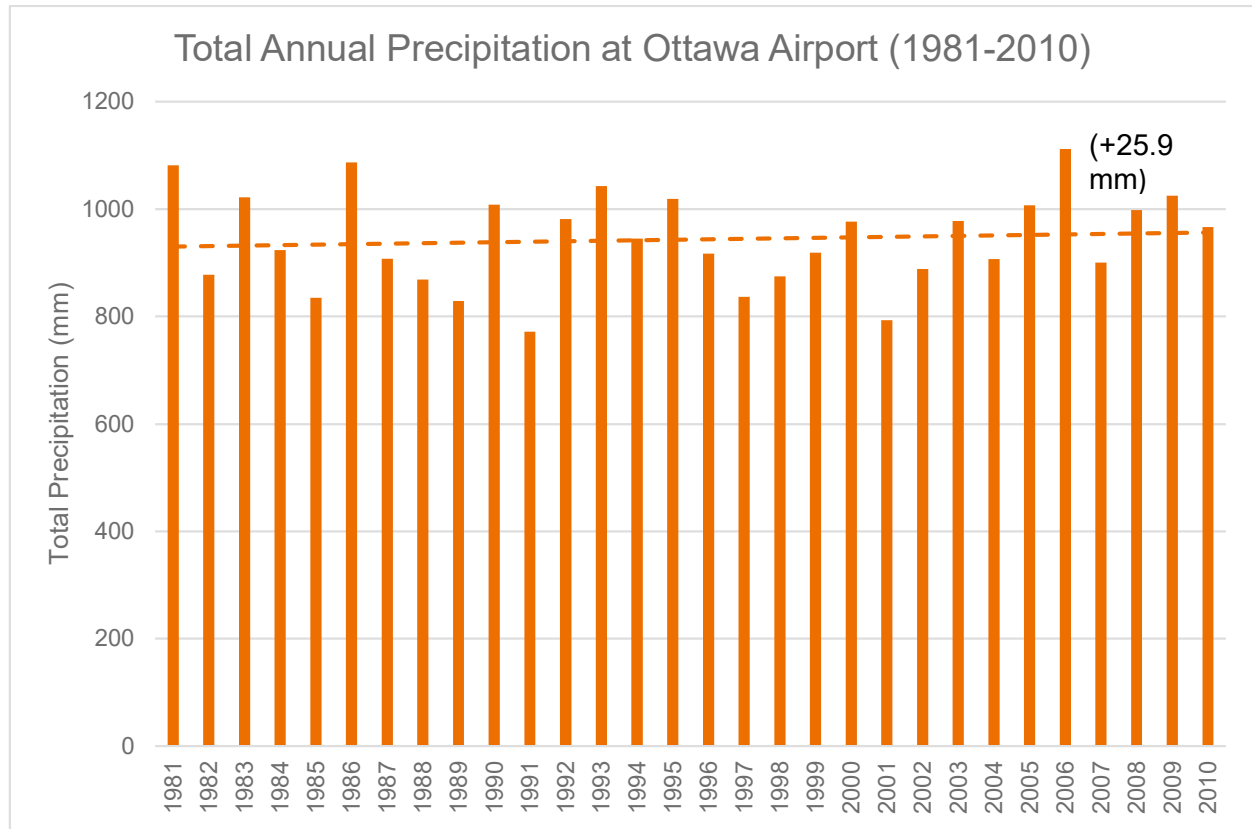


Figure 8 1981-2010 Total Annual Precipitation Data and Trend at Ottawa Airport

Trend analysis of changes in Canadian precipitation and, in particular, extreme precipitation is challenging due in part to the low spatial density of the precipitation data and especially the rate-of-rainfall (tipping bucket rain gauge) station network, with many rate-of-rainfall station records being considerably out-of-date (e.g. by a decade). Subsequently, statistically significant and conclusive evidence on changes in (extreme) precipitation are difficult to obtain from Canadian stations. Nevertheless, an overall increase in total annual rainfall has been observed for Southern Ontario since the 1950s (Mekis and Vincent, 2011; Bush et al., 2014), with more increasing (though often not statistically significant) trends than decreasing trends in extreme rainfall having also been detected (Bush et al., 2014; Shephard et al., 2014; Mekis et al., 2015; Vincent et al., 2018).



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Regional trend analyses (regionally averaged station data) have been found to detect stronger trends compared to the use of individual station records (Shephard et al., 2014; Soulis et al., 2016). For instance, Soulis et al. (2016) determined that extreme rainfall, averaged for all of Ontario, has increased by 1.8% per decade for 24-hr duration events and by 1.25% per decade for 30-minute duration events during the 1960-2010 period. In contrast to Canadian extreme precipitation research results, U.S. studies have been more conclusive in showing statistically significant increasing regional trends in extremes (e.g. in the US Northeast and Midwest; Figure 9) (Walsh et al., 2014; Easterling et al., 2017). In part, these trend differences can be linked to geographical regions and indicators and their threshold levels, although differences in the density of the observing networks may be a main contributor. Many of these increasing trends are being observed in states directly bordering Canada, including Southern Ontario (Figure 9), and there is no reason to believe that similar (i.e. increasing) trends to these detected US trends would not also be evident north of the border but are masked by the observation network data itself.

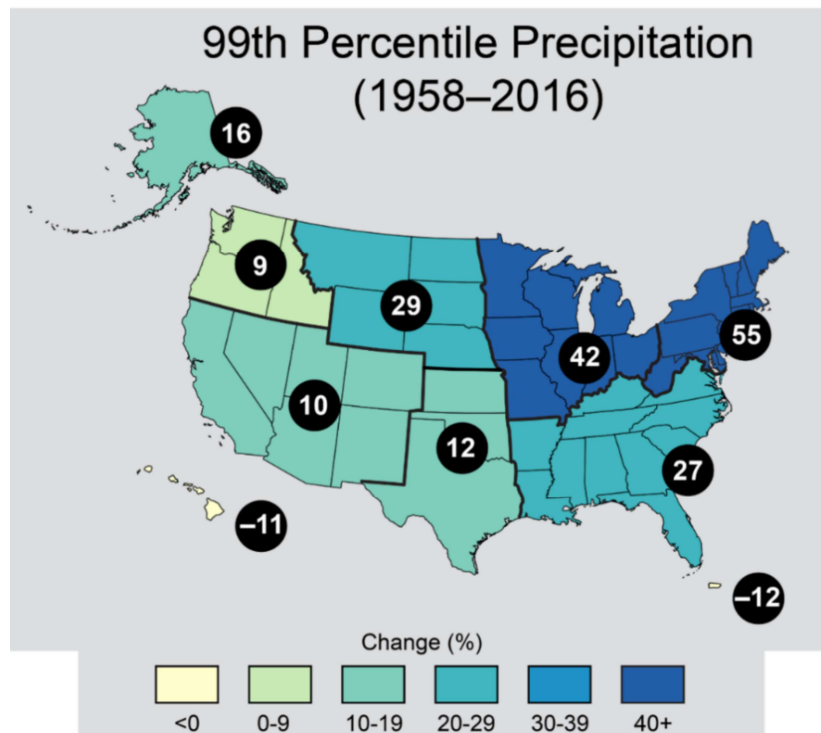


Figure 9 Percent increases in the amount of precipitation falling in daily events that exceed the 99th percentile of all days with precipitation (i.e. the total precipitation falling in the top [heaviest] 1% of daily precipitation events) in the United States, 1958-2012, calculated from daily precipitation total observations. Figure from Easterling et al., 2017.

Severe weather extreme events, such as freezing rain and ice storms, lightning, high winds and tornadoes, can result in significant impact and damage to electrical infrastructure and are influenced by the changing climate. Historical research was able to confirm four major freezing rain and ice storm events, i.e., those which resulted in long term and widespread power and communication outages,



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affecting the Greater Ottawa Region since 1940, including the most recent April 2018 event as well as the infamous January 1998 ice storm (Klaassen et al., 2003; Local media sources). Across the Greater Ottawa Region, lightning flash density varies from approximately 1.0 to 1.2 flashes per square kilometer (ECCC National Lightning Database). Eastern Ontario and Western Quebec have also historically been subject to periodic significant tornado outbreaks, including the recent September 21, 2018 tornado outbreak which included three significant (EF2 and EF3) tornadoes impacting the Greater Ottawa Region. Gensini and Brooks (2018) also report an observed increase in days with potential for significant tornado development in northeastern North America over the past ~40 years.

Under climate change, observed trends are projected to continue. Table 5 outlines general projected changes in climate parameters of interest to Hydro Ottawa’s electrical distribution system, services, and operations.

Table 5 Summary of Potential Climatic Changes By Mid-Century in the Greater Ottawa Region

Climate Parameter	Projected Climatic Changes by Mid-Century
Temperature – Extreme Heat	<ul style="list-style-type: none"> Increased frequency and intensity Increased frequency and length of heat waves
Temperature – Extreme Cold	<ul style="list-style-type: none"> Decreased frequency and intensity Occurrence of extreme cold outbreaks (“Polar Vortex” winters) likely to continue
Rain (Short Intensity – High Duration)	<ul style="list-style-type: none"> Increased intensity of events Reduced return periods (e.g. 20-yr return period event becoming a 10-yr return period event)
Freezing Rain & Ice Storms	<ul style="list-style-type: none"> Increased frequency Increased winter season (e.g. January) events
Snow	<ul style="list-style-type: none"> Likely decrease in annual total accumulation Continued occurrence and steady frequency of larger individual events
High Winds	<ul style="list-style-type: none"> Slight increase in frequency of high wind events (e.g. 90 km/hr; 120 km/hr)
Lightning	<ul style="list-style-type: none"> Increased frequency (by about 12% per degree Celsius of warming) Increased length of the higher frequency lightning season
Tornadoes	<ul style="list-style-type: none"> Increased frequency (25% increase by mid-century) Increase (near 2x) in number of severe thunderstorm days by mid-century (capable of possibly producing tornadoes, hail, extreme winds, and extreme rainfall events)
Fog	<ul style="list-style-type: none"> Likely increase
Frost (Freeze-Thaw Cycles)	<ul style="list-style-type: none"> Decrease in annual total number of freeze-thaw days Increase in monthly totals in the shoulder seasons (e.g. November and March)



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4.3 SPECIAL EVENT FORENSICS

4.3.1 Climate Event Forensic Analysis

Individual high-impact severe weather events can produce disproportionate amounts of damage to electrical distribution systems. These events test the capacity and limitations of response crews, often necessitating prioritization of repairs and leaving some customers without power for several days. However, by conducting investigations of these events, particularly by combining infrastructure impacts information and weather observations, lessons can be learned, and response strategies can be developed to increase the resiliency of the electrical distribution network to help bolster resilience.

Hydro Ottawa identified three high-impact severe weather events as part of the overall scope of the PIEVC assessment:

- April 15-16, 2018 – ice and wind storm;
- May 4, 2018 – wind storm; and,
- September 21, 2018 – tornado outbreak.

The forensic assessment was conducted by combining information on both infrastructure impacts and meteorological data, with the intent of establishing the following:

- **Event Timelines** – Understanding the progression of events leading up to, during, and immediately following major outage events;
- **Meteorological/Climate Diagnosis** – Determine the type, extent, and severity of weather/climate event responsible for outages; and,
- **Develop Adaptation Recommendations** – Determine actions that can be taken to assist in the preparation and response to similar events in the future.

A summary of each case study is provided below, followed by a list of adaptation actions stemming from this review. A much more detailed description of forensic assessment methodology, case study analyses and results are provided in **Appendix A**. Possible adaptation actions related to these events will be included in the adaptation report.

4.3.2 Ice and Wind Storm - 15 - 16 April 2018

A combined wind and ice storm resulted in a total of 73,797 customers losing power during this event. Ottawa airport reported a total of 16 hours of freezing precipitation between noon EDT on April 15th and 10 AM EDT April 16th. The freezing rain and drizzle resulted in ice accumulations on overhead electrical infrastructure and adjacent vegetation exceeding 10 mm in total thickness, which was accompanied by strong winds gusting to 67 km/h on April 15 and 74 km/h on April 16. Total estimated ice accumulations by midnight on April 15th were likely around 10 mm, resulting in a small number of scattered power outages. However, between 7 AM and 2 PM on April 16th, the total number of outages increased from approximately 4,000 customers to over 43,000 customers.



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Since combined loading from wind and ice are challenging to assess, efforts have been made in other jurisdictions to estimate the potential impacts from various combinations of wind and ice loads. The Sperry-Piltz Ice Accumulation (SPIA) Index (Figure 10), a combined ice and wind load scale, is increasingly being used for such events by meteorologists and contains 6 categories of increasing severity (0-5).

The April 15 - 16 2018 event would have been ranked a “4” on the 0-5 scale, corresponding to much more severe impacts than what was observed. This is likely due to the SPIA Index’s development in the central United States (originally the Tulsa, Oklahoma local weather office), and therefore impact statements correspond to infrastructure designed to lower ice and wind combination thresholds.

The Sperry-Piltz Ice Accumulation Index, or “SPIA Index” – Copyright, February, 2009

ICE DAMAGE INDEX	* AVERAGE NWS ICE AMOUNT (in inches) <small>*Revised-October, 2011</small>	WIND (mph)	DAMAGE AND IMPACT DESCRIPTIONS
0	< 0.25	< 15	Minimal risk of damage to exposed utility systems; no alerts or advisories needed for crews, few outages.
1	0.10 – 0.25	15 - 25	Some isolated or localized utility interruptions are possible, typically lasting only a few hours. Roads and bridges may become slick and hazardous.
	0.25 – 0.50	> 15	
2	0.10 – 0.25	25 - 35	Scattered utility interruptions expected, typically lasting 12 to 24 hours. Roads and travel conditions may be extremely hazardous due to ice accumulation.
	0.25 – 0.50	15 - 25	
	0.50 – 0.75	< 15	
3	0.10 – 0.25	> = 35	Numerous utility interruptions with some damage to main feeder lines and equipment expected. Tree limb damage is excessive. Outages lasting 1 – 5 days.
	0.25 – 0.50	25 - 35	
	0.50 – 0.75	15 - 25	
	0.75 – 1.00	< 15	
4	0.25 – 0.50	> = 35	Prolonged & widespread utility interruptions with extensive damage to main distribution feeder lines & some high voltage transmission lines/structures. Outages lasting 5 – 10 days.
	0.50 – 0.75	25 - 35	
	0.75 – 1.00	15 - 25	
	1.00 – 1.50	< 15	
5	0.50 – 0.75	> = 35	Catastrophic damage to entire exposed utility systems, including both distribution and transmission networks. Outages could last several weeks in some areas. Shelters needed.
	0.75 – 1.00	> = 25	
	1.00 – 1.50	> = 15	
	> 1.50	Any	

Figure 10 SPIA Index (Sperry, 2009) describing combination of wind and ice loading and expected impacts. Note that the scale currently over-estimates the severity of associated impacts to the Hydro Ottawa system and would require further tailoring for use in eastern Canada.



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Main impacts were the result of trees and branches impacting lines; however, several utility poles (33 in total) also suffered structural failures. It is notable that many poles did not fail at the ground line in this case but rather several meters above the ground line. This may be due to significant lateral loading from wind action on ice covered lines, in which case the highest fiber stress within a utility pole can occur above the ground line. We also note that Hydro Ottawa's post storm investigation indicated a small number of the poles were also potentially aged and degraded, which may have further contributed to failures.

4.3.3 High Wind Event - 4 May 2018

An intense low-pressure system tracked across a large portion of southern Ontario through to southern Quebec and adjacent areas of the United States, resulting in power outages for approximately 45,000 Hydro Ottawa customers. Damage reports, mainly consisting of large branches and individual trees being uprooted, was first reported in eastern Michigan in the Detroit area at 1:09 PM EDT. As the storm moved across southern Ontario, wind gusts approaching or exceeding 120 km/h were recorded at several locations. Widespread wind damage was reported across the Kitchener-Waterloo and Golden Horseshoe regions beginning after 3 pm EDT, including three fatalities attributed to the storm, as well as damage consisting of large branches and/or large trees snapped or uprooted, shingles and portions of roofs removed from homes and commercial buildings, and tens of thousands of electrical distribution customers in multiple jurisdictions losing power.

High winds and associated customer outages occurred in two distinct "waves" which were associated with different portions of the weather system (Figure 11). Several locations southwest of the City of Ottawa first reported wind related power outages after 7 PM EDT, with a total of 11,000 customers losing power in Kanata, Stittsville, Richmond and Munster by 7:48 PM. This first wave of high winds continued east-northeast, triggering similar outages in the Finlay Creek area by 8:50 PM. The second period of high winds, which also appeared to be more severe than the first, began in the late evening, with most damage occurring roughly between 10 and 11:30 PM EDT. By 11:40 PM EDT, Hydro Ottawa reported that in excess of 30,000 customers had lost power. The worst affected areas in the City of Ottawa following the second, late evening period of high winds required more than a day of repair work to fully restore power.



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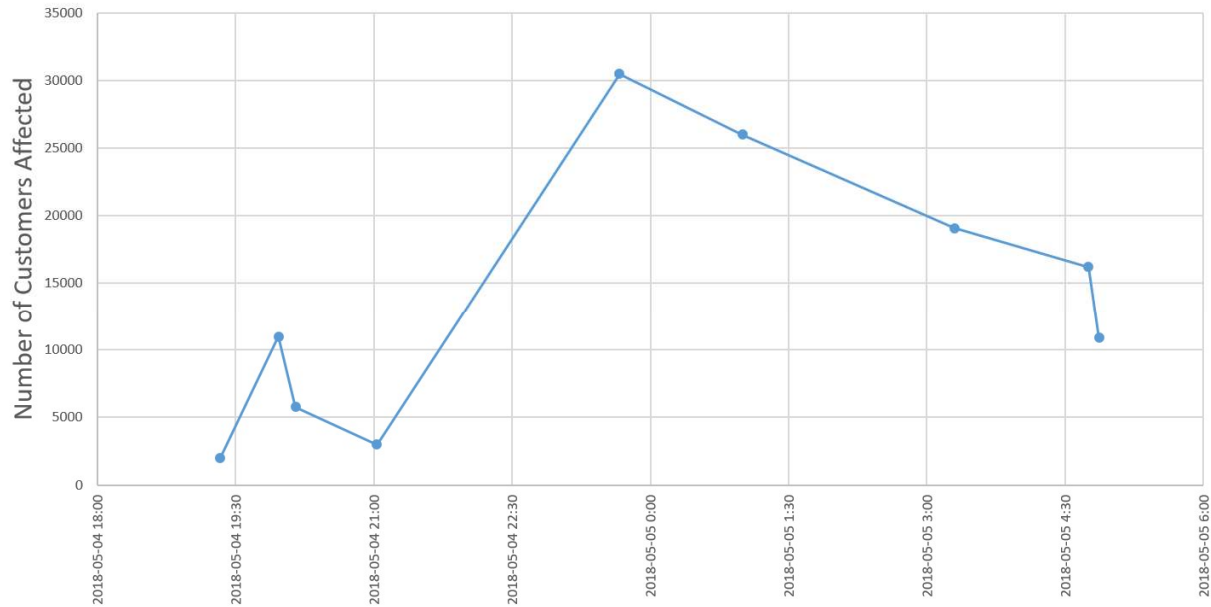


Figure 11 Timeline describing number of customers affected during May 4, 2018 windstorm. Note small peak of ~11,000 between 7:30 and 8:00 PM EDT, followed by much larger peak of >30,000 later in the evening. Total number of customers affected based on outages reported by Hydro Ottawa’s Twitter account.

With such a large-scale wind event, the potential existed for understanding potential impacts to Hydro Ottawa’s electrical system by monitoring upstream utilities and meteorological data. In addition to high winds reported at various airports across southern Ontario, local utilities suffered widespread outages several hours prior to Hydro Ottawa, including utilities in the Kitchener-Waterloo region (~35,000 customers) Toronto Hydro (over 30,000), and Hydro One’s rural distribution network (over 126,000 customers affected). Damage reported by media and Hydro Ottawa staff also suggest that winds were likely stronger in some parts of the City of Ottawa than those measured at the airport. A peak gust of 96 km/h was recorded in the late evening, but cladding and shingle damage to homes, as well as some more intense damage to trees and branches in some areas, suggest winds exceeded 105 km/h in some isolated locations within the service area.



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4.3.4 Tornado Outbreak - 21 September 2018

The September 21, 2018 tornado outbreak consisted of at least 7 separate tornadoes, with Hydro Ottawa’s service area suffering impacts from the two strongest confirmed tornadoes within the outbreak, the long-tracked Kinburn-Dunrobin-Gatineau tornado, rated EF-3 on the 0 to 5 EF-scale of tornado intensity, and the Nepean-South Ottawa tornado, rated EF-2. The Kinburn-Dunrobin-Gatineau tornado formed at approximately 4:32 PM EDT, tracking roughly northeast until crossing the Ottawa River at approximately 4:52 PM EDT. Approximately one hour later, at 5:51 PM EDT, the Nepean tornado formed in association with a second line of storms. This tornado impacted the Merivale Transmission Station (TS) at almost exactly 6:00 PM EDT, resulting in a significant proportion of outages triggered in this event, and dissipated shortly after at approximately 6:09 PM EDT. All damage associated with these tornadoes, resulting in over 174,000 customers being affected, occurred in a time span of approximately 38 minutes (Figure 12).

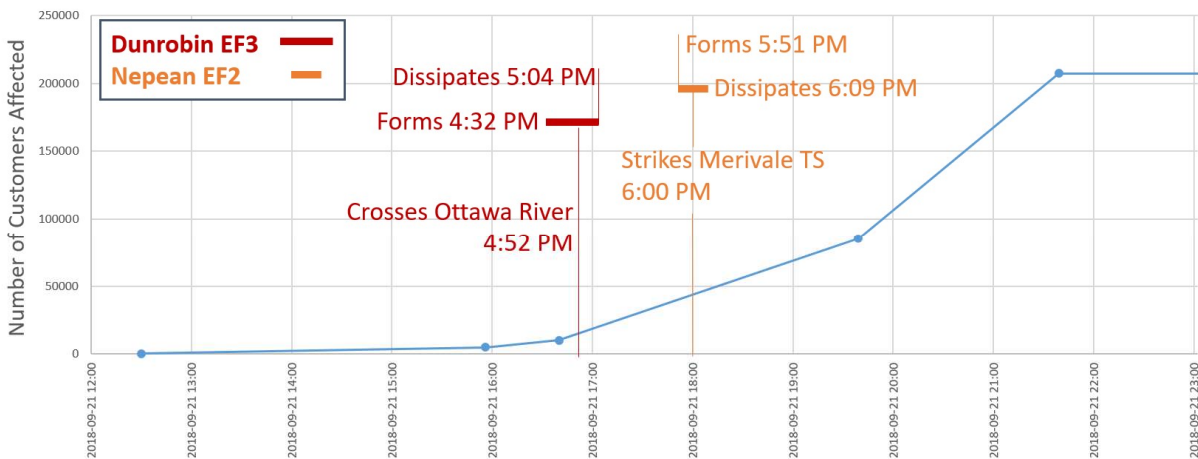


Figure 12 Timeline comparing the total number of reported customers affected versus the occurrence of the Kinburn-Dunrobin-Gatineau tornado (red) and the Nepean-South Ottawa tornado (orange). Outage totals are based on those reported by Hydro Ottawa’s Twitter account and the final total based on post-event reports.

Based on a review of historical events, this appears to be the first day in recent history in which two significant (i.e., EF-2 or stronger) tornadoes affected Hydro Ottawa’s service area on the same day. Damage surveys conducted by teams from Environment and Climate Change Canada (ECCC) and the University of Western Ontario (UWO) wind engineering group helped better clarify what occurred at Merivale TS. In spite of the widespread impacts of this direct strike on the station, the tornado was likely at EF-1 intensity when these impacts occurred, suggesting maximum winds of around 170 km/h.



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5.0 RISK ASSESSMENT

As discussed previously, the risk assessment is an iterative and highly participatory process that identifies risks through the use of data and other available information which is then validated by key stakeholders, and a strong focus on local knowledge. The following sections outline the components of the risk assessment and the process by which the final risk profile was developed.

5.1 INTERVIEWS

A series of interviews with Hydro Ottawa staff within their Operations, Engineering and Design, and Emergency Planning and Response divisions was completed to provide detailed information to inform the climate risk assessment. Three 1.5-hour interviews took place on March 7th and 8th, 2019 and each included 3-4 participants from Hydro Ottawa. A full list of interview participants is provided in Table 6. Discussion during these interviews was guided by a prepared list of questions but was encouraged to wander when relevant points arose. The information provided during these interviews helped to identify the climate risks that Hydro Ottawa is exposed to and introduced an appreciation for the challenges and vulnerabilities that could potentially be mitigated through changes in their operations, design, and response policy and practices. A summary of the discussion that took place during these interview sessions is provided in **Appendix B**.

The following participants attended the interview sessions that took place on March 7-8, 2019.



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Table 6 List of Interview Participants and their Roles

Participant	Role
Guy Felio	Interviewer (Stantec)
Riley Morris	Interviewer (Stantec)
Matthew McGrath	Project Manager (Hydro Ottawa)
Operations Staff – March 7, 2019	
Greg Bell	Manager, Distribution Operations (Underground)
Brent Fletcher	Manager, Program Management and Business Performance
Jeff Bracken	Manager, Distribution Operations (Overhead)
Engineering and Design Staff – March 7, 2019	
Margret Flores	Supervisor, Asset Planning
Jenna Gillis	Manager, Asset Planning
Tony Stinziano	Manager, Distribution Design
Ben Hazlett	Manager, Distribution Policies and Standards
Emergency Planning and Response – March 8, 2019	
Doug Baldock	Manager, System Operations
Brian Kuhn	Manager, Distribution Operations (Overhead)
Adam MacGillivray	Business Continuity Management Specialist

5.2 INFRASTRUCTURE

The following subsections outline the main components of the risk assessment as they relate to the infrastructure.

5.2.1 Infrastructure List Validation

Validation is a key step in the risk assessment process. The infrastructure list was validated through a number of means, listed as follows.

- Consultation with a subject matter expert;
- Validation through Hydro Ottawa project manager; and,
- Validation through the climate risk and vulnerability workshop.

At each of these revision steps, individuals provided comments that were incorporated into the list of infrastructure.



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5.2.2 Performance Criteria

The performance criteria are variables that describe different perspectives from which we can assess risks to the system's infrastructure. A summary of performance criteria response categories is provided along with their descriptors in Table 7. These performance criteria were selected by the Project Team to match Hydro Ottawa's Asset Management Risk Procedure (see Figure 2), thus allowing the use of the PIEVC assessment results to inform corporate risks and decision-making.

Table 7 Performance Criteria Considered in the Risk Assessment

Response Category	Description
Level of Service: System Accessibility	Risk or opportunity impacting the connection of load and energy resource facility customers.
Level of Service: Service Quality	Risk or opportunity impacting the delivery of electric power in a form which meets customer's needs.
Resource Efficiency	Risk or opportunity impacting the additional use of internal or external resources.
Asset Value: Financial	Risk or opportunity impacting the realization of value from assets through resulting financial expense.

5.2.3 Severity Ratings

More than simply understanding that an interaction between the climate and infrastructure components exists, it is important to assess the consequence (impact) on the assets should the climate or weather event occur. The ratings place numerical values on the severity that a climate event would have on an infrastructure component. Similar to the performance criteria (**Section 5.2.2**), the severity scoring system was selected to readily integrate into the AMRP, as summarized in Figure 2. The 1- to 25-point severity scale and the descriptions used in defining the performance descriptors were extracted directly from Hydro Ottawa's AMRP.



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Table 8 Severity Ratings used in the Risk Assessment

Severity Score and Descriptor		Infrastructure Performance and Severity Rating			
		Level of Service: System Accessibility	Level of Service: Service Quality	Resource Efficiency	Asset Value - Financial
Insignificant	1	N/A	Service interruption resulting in <10,000 customer minutes interrupted. Service quality resulting in customer complaint, but meets CSA standards	Requires <10 hours of overtime to complete O&M work or undergo training. Requires <100 hours of overtime to complete capital work.	Financial risk resulting in an O&M expense of <\$1k. Financial risk resulting in a capital expense of <\$10k.
Minor	4	N/A	Service interruption resulting in >10,000 customer minutes interrupted. Service quality resulting in customer escalation, but meets CSA standards	Requires >10 hours of overtime to complete O&M work or undergo training. Requires >100 hours of overtime to complete capital work.	Financial risk resulting in an O&M expense of >\$1k. Financial risk resulting in a capital expense of >\$10k.
Moderate	9	Load demand/generation is exceeding planning limits.	Service interruption resulting in >500,000 customer minutes interrupted.	Requires >250 hours of overtime to complete O&M work or undergo training. Requires >2,500 hours of overtime to complete capital work.	Financial risk resulting in an O&M expense of >\$50k. Financial risk resulting in a capital expense of >\$500k.
Major	16	Load demand/generation is exceeding thermal limits.	Service interruption resulting in >3,000,000 customer minutes interrupted.	Requires >1,500 hours of overtime to complete O&M work or undergo training. Requires >15,000 hours of overtime to complete capital work.	Financial risk resulting in an O&M expense of >\$300k. Financial risk resulting in a capital expense of >\$3M.
Catastrophic	25	Unable to service new load/ERFs	Service interruption resulting in >10,000,000 customer minutes interrupted. Service quality resulting in not meeting CSA standards.	Unable to complete work with internal and/or external resources due to volume or skill gap.	Financial risk resulting in an O&M expense of >\$1M. Financial risk resulting in a capital expense of >\$10M.



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5.3 CLIMATE CHANGE

This section provides an overview of the climate probability scoring methodology and parameter threshold values used in the risk assessment. These items are discussed in more detail in the Climate Change Hazards Report, provided as **Appendix A**.

5.3.1 Climate Probability Scoring

Statistical information for both historical (1981-2010) and projected (2050s) event frequencies of the identified climate parameters and the five-point scoring scale used in Hydro Ottawa’s Asset Management System Risk Procedures (Table 9) were used to develop probability scores for this study. A score of 1 refers to a climate event that is “rare” and has a very low likelihood of occurring during the time period of interest, while a score of 5 refers to an event that is “almost certain” and highly likely to occur in the period.

Table 9 Probability Scoring Scale Used in Hydro Ottawa’s Asset Management System Risk Procedures

Probability Score	Descriptor	Detailed Description	Probability Range
1	Rare	May only occur in time period under exceptional circumstances	$p \leq 5\%$
2	Unlikely	Could occur in time period	$5\% < p \leq 35\%$
3	Possible	Might occur in time period	$35\% < p \leq 65\%$
4	Likely	Will probably occur in time period	$65\% < p \leq 95\%$
5	Almost Certain	Is expected to occur	$95\% < p$

In this study, the probabilities of an event directly impacting the Hydro Ottawa service area – both on an annual basis and over the future 30-year time horizon, are used. The annual probability of an event occurring provides insight for functional and operational (O&M) impacts while the probability over a 30-year period provides insight for structural impacts.

5.3.2 Climate Thresholds

Historical baseline (1981-2010) and projected climate change (2050s) information under the RCP8.5 scenario for the identified climate parameters is presented in Table 9 below. The Table also provides a summary of the analytical results (annual and 30-year probabilities and scores). Annual averages (frequencies) for each parameter are provided in terms of events per year (yr^{-1}). Probability values (%) are calculated based on the probability of an event directly impacting the Hydro Ottawa service area. The probability scores, ranked from 1 to 5, are used to calculate risk values and will appear in the risk assessment worksheet summarizing the overall results of the risk assessment. Detailed discussions for each climate parameter are provided in **Appendix A**.



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Table 10 Annual and 30-Year Probabilities and Scores for the Historical Baseline (1981-2010) and Future Climate (2050s) under the RCP8.5 Scenario

Climate Thresholds	Baseline Probabilities			2050s Probabilities (RCP8.5)			Change in Probability Score	
	Annual Probability	30-Year Probability	30-Year Probability Score	Annual Probability	30-Year Probability	30-Year Probability Score	Annual Probability	30-Year Probability
Temperature – Extreme Heat								
Daily maximum temp. of 30°C and higher	100% (~14-15 yr ⁻¹)	100%	5	100% (~42 yr ⁻¹)	100%	5	No change	No change
Daily maximum temp. of 35°C and higher	50% (< 1 yr ⁻¹)	>99%	3	100% (~6 yr ⁻¹)	100%	5	+ 2	No change
Daily maximum temp. of 40°C and higher	6% (< 1 yr ⁻¹)	84%	2	100% (~1-2 yr ⁻¹)	100%	5	+ 3	+ 1
Daily average temp. of 30°C and higher	3% (< 1 yr ⁻¹)	60%	1	100% (~1-2 yr ⁻¹)	100%	5	+ 4	+ 2
Heat wave: Consecutive days with T _{max} ≥ 30°C and T _{min} ≥ 23°C	7% (< 1 yr ⁻¹)	89%	2	100% (~2 yr ⁻¹)	100%	5	+ 3	+ 1
Heat wave: Consecutive days with T _{max} ≥ 30°C and T _{min} ≥ 25°C	0% (0 yr ⁻¹)	0%	1	37% (< 1 yr ⁻¹)	>99%	5	+ 2	+ 4
Temperature – Extreme Cold								
Daily minimum temp. of -35°C and colder	3% (< 1 yr ⁻¹)	60%	1	0.1% (Rare)	3%	1	No change	- 2
Rain								
50 mm of rainfall in 1 hour	1% (< 1 yr ⁻¹)	~25%	1	4.5% (< 1 yr ⁻¹)	75%	4	No change	+ 2



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Climate Thresholds	Baseline Probabilities				2050s Probabilities (RCP8.5)				Change in Probability Score	
	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	30-Year Probability
Freezing Rain & Ice Storms										
Ice accumulation of 25 mm	5% (< 1 yr ⁻¹)	1	79%	4	6% (< 1 yr ⁻¹)	2	84%	4	+ 1	No change
Ice accumulation of 40 mm	2.5% (< 1 yr ⁻¹)	1	>50%	3	3.8% (< 1 yr ⁻¹)	1	~70%	4	No change	+ 1
Snow										
Days with 5 cm or more of snowfall	100% (~15 yr ⁻¹)	5	100%	5	100% (~15 yr ⁻¹)	5	100%	5	No change	No change
Days with 10 cm or more of snowfall	100% (~5-6 yr ⁻¹)	5	100%	5	100% (~5 yr ⁻¹)	5	100%	5	No change	No change
Days with 30 cm or more of snowfall	13% (< 1 yr ⁻¹)	2	98%	5	10% (< 1 yr ⁻¹)	2	>95%	5	No change	No change
High Winds										
Annual wind speeds of 60 km/hr or higher	100% (~14-15 yr ⁻¹)	5	100%	5	100% (~16 yr ⁻¹)	5	100%	5	No change	No change
Easterly winds of 60 km/hr or higher (warm season [April - Sept.])	28.9% (< 1 yr ⁻¹)	2	100%	5	32.4% (< 1 yr ⁻¹)	2	>99%	5	No change	No change
Easterly winds of 60 km/hr or higher (summer [June-Aug.])	2.6% (< 1 yr ⁻¹)	1	55%	3	2.9% (< 1 yr ⁻¹)	1	~60%	3	No change	No change
Annual wind speeds of 80 km/hr winds or higher	100% (~1-2 yr ⁻¹)	5	100%	5	100% (~1-2 yr ⁻¹)	5	100%	5	No change	No change



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Risk Assessment
 November 11, 2019

Climate Thresholds	Baseline Probabilities				2050s Probabilities (RCP8.5)				Change in Probability Score	
	Annual Probability	30-Year Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	30-Year Probability
Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	5.3% (< 1 yr ⁻¹)	2	80%	4	6.3% (< 1 yr ⁻¹)	2	85%	4	No change	No change
Easterly winds of 80 km/hr or higher (winter [Dec.-Feb.])	2.6% (< 1 yr ⁻¹)	1	55%	3	3.2% (< 1 yr ⁻¹)	1	>60%	3	No change	No change
Annual wind speeds of 90 km/hr or higher	23% (< 1 yr ⁻¹)	2	>99%	5	29% (< 1 yr ⁻¹)	2	>99%	5	No change	No change
Annual wind speeds of 120 km/hr or higher	2.5% (< 1 yr ⁻¹)	1	53%	3	3.1% (< 1 yr ⁻¹)	1	61%	3	No change	No change
Lightning										
Strikes near infrastructure (flashes/ km ² / year)	1.1% (< 1 yr ⁻¹)	1	28%	2	1.5% (< 1 yr ⁻¹)	1	36%	3	No change	+ 1
Tornadoes										
EF1+ in Hydro Ottawa service area (City of Ottawa)	14.6% (< 1 yr ⁻¹)	2	>99%	5	18.2% (< 1 yr ⁻¹)	2	>99%	5	No change	No change
EF1+ point probability (i.e. striking a specific asset in City of Ottawa service area)	0.018% (Rare)	1	0.6%	1	0.023% (Rare)	1	0.7%	1	No change	No change
Invasive Species										
Emerald Ash Borer (Daily min. temp. of -30°C or colder [kill temp.])	53% (< 1 yr ⁻¹)	3	>99%	5	3% (< 1 yr ⁻¹)	1	60%	3	- 2	- 2
Giant Hogweed (3 consecutive days of -8°C or colder [germination requirement])	100% (25 yr ⁻¹)	5	100%	5	100% (17 yr ⁻¹)	5	100%	5	No change	No change



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Risk Assessment
 November 11, 2019

Climate Thresholds	Baseline Probabilities				2050s Probabilities (RCP8.5)				Change in Probability Score	
	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	30-Year Probability
Fog										
Season with ≥ 50 fog days (Nov.-March)	37%	3	100%	5	Likely increase	3-4	100%	5	Possibly +1	No change
Frost										
Freeze-thaw cycles – Daily Tmax Tmin temp. fluctuation around 0°C	100% (~2-3 yr ⁻¹)	5	100%	5	100% (~2 yr ⁻¹)	5	100%	5	No change	No change
Freeze-thaw cycles – Daily Tmax Tmin temp. fluctuation of ±4°C around 0°C	30% (< 1 yr ⁻¹)	2	>99%	5	38% (< 1 yr ⁻¹)	3	>99%	5	+1	No change



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Risk Assessment
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5.4 RISK WORKSHOP

A climate risk workshop took place on April 12, 2019 where the risk assessment team worked with Hydro Ottawa staff and representatives from the City of Ottawa to acquire input on the assessment. The purpose of the workshop was to: (1) validate any assumptions made in the work done thus far and (2) seek guidance on assigning severity ratings to climate-infrastructure interactions. The assessment components validated during the risk workshop are listed as follows:

- Risk assessment process
- Severity ratings
- Climate probability scoring system
- Infrastructure response criteria (derived from the Hydro Ottawa Risk Management Plan)
- List of infrastructure
- Climate parameters and threshold values

Comments made towards these risk assessment components were later incorporated into the assessment.

The risk evaluation process is depicted graphically in Figure 13.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Risk Assessment
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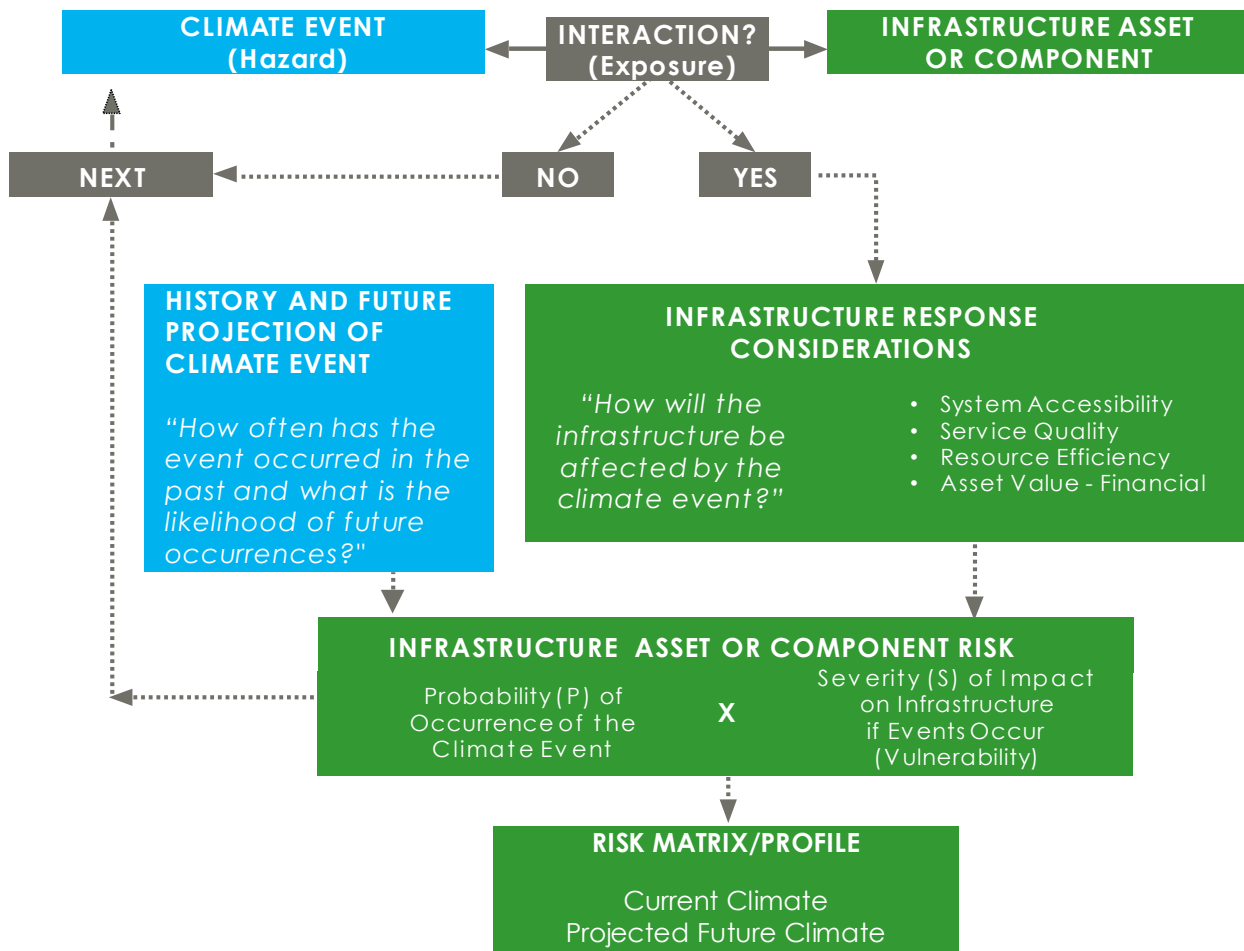


Figure 13 Flow Chart Describing Risk Evaluation Process

For the second portion of the risk workshop, the participants and facilitators broke off into two working groups of 8-10 individuals per group. This step involved the completion of a 'yes/no' analysis where the working group identifies which infrastructure elements are exposed to each climate parameter. From here, only those climate-infrastructure interactions associated with a 'yes' will be considered in the risk assessment. The working groups then began assigning severity ratings to those climate-infrastructure interactions that remained in the assessment. These severity scores are established by considering the consequence on the infrastructure elements when a climate event, at the selected intensity threshold, occurs. In most instances, the groups noted 'no' to 'low' impact to the asset, however, some higher order impacts were noted.

This input was documented on the risk worksheet which will be described in detail under **Section 5.5** and notes taken during the risk assessment workshop are provided in **Appendix C**. A list of participants who attended the risk assessment workshop is summarized in Table 11.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Risk Assessment
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Table 11 List of Participants Who Attended the Risk Assessment Workshop

Participant	Role
Facilitators	
Nicole Flanagan	Stantec, Project Manager
Guy Félio	Stantec, Climate Change Resilience Advisor
Riley Morris	Stantec, Environmental Engineer
Eric Lafleur	Stantec, Electrical Engineer, Subject Matter Expert
Heather Auld	RSI, Climatologist
Norman Shippee	RSI, Climatologist
Simon Eng	RSI, Climate Analyst
Katherine Pingree-Shippee	RSI, Climatologist
Workshop Participants	
Matthew McGrath	Hydro Ottawa, Project Manager
Greg Bell	Hydro Ottawa, Manager, Distribution Operations (Underground)
Margret Flores	Hydro Ottawa, Supervisor, Asset Planning
Tony Stinziano	Hydro Ottawa, Manager, Distribution Design
Ben Hazlett	Hydro Ottawa, Manager, Distribution Policies and Standards
Adam MacGillivray	Business Continuity Management Specialist
Greg Van Dusen	Hydro Ottawa, Director, Regulatory Affairs
Joseph Muglia	Hydro Ottawa, Director, Distribution Operations
Ed Donkersteeg	Hydro Ottawa, Supervisor, Standards
Tammy Rose	City of Ottawa, Water Services
Jennifer Brown	City of Ottawa, Project Manager, Climate Change and Resilience Unit
David Lapp	Engineers Canada, Manager, Globalization and Sustainable Development

A follow-up working session comprised of select members of the workshop team took place on May 8, 2019 to complete severity scoring work that could not be completed during the workshop. The final risk worksheet was then circulated to Hydro Ottawa staff for further comments and validation.

5.5 RISK WORKSHEET

The risk worksheet used to assess the severity of impacts of climate events on the infrastructure was based on the original PIEVC Protocol template, adapted to the performance criteria and ratings selected for the Hydro Ottawa assessment. One worksheet was prepared for each the current and future projected (2050s) climate assessments.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

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Figure 14 shows a cut-out of the worksheet which contains three main elements:

1. The asset/infrastructure list broken down in major components that may be affected differently by climate events of various intensity;
2. The climate events selected for the assessment, including a description of the selected intensity threshold and the probability (likelihood) of occurrence (current or future climates);
3. The climate-infrastructure interactions assessment:
 - a. Exposure (Yes/No);
 - b. Severity of impact (S) and risk (R) following the selected performance criteria:
 - o Sa/Ra: Level of Service: System Accessibility
 - o Sq/Rq: Level of Service: Service Quality
 - o Se/Re: Resource Efficiency
 - o Sf/Rf: Asset Value - Financial

Asset/Infrastructure Element	Climate 1										Climate 2									
	Daily maximum temp. of 35°C and higher										Daily maximum temp. of 40°C and higher									
Current Climate	Probability = 3										Probability = 2									
	Final					Final					Final					Final				
	Y/N	Sa	Sq	Se	Sf	Ra	Rq	Re	Rf	Y/N	Sa	Sq	Se	Sf	Ra	Rq	Re	Rf		
1) City of Ottawa																				
a) General System-Wide Assets																				
Substations																				
Buildings and Structural Components																				
P&C Buildings																				
Switchgear Buildings																				
Equipment Support Structures																				
Station Yard																				
Station Load Break Switch																				
Station Capacitor Voltage Transformers																				
Station Circuit Breakers																				
Indoor Breakers																				
Outdoor Breakers (Metalclad)																				
Station Power Transformers																				
Surge Arrestors																				
Bushings																				
Radiators																				
Fans																				
Control Cabinet																				

Figure 14 Extract from the Risk Worksheet Used During the Assessment Workshop

At the risk assessment workshop, the participants followed the process illustrated in Figure 13 above.



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

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5.5.1 Special Cases

In this assessment, certain climate parameters were excluded from the typical PIEVC risk worksheet process outlined above, since they are either extreme events (e.g., tornadoes) or indirect risks due to a combination of climate events (e.g., wild fires due to drought and high temperatures, lightning strikes, or human activities).

5.5.1.1 Tornadoes

The climate study performed for this assessment indicated a high likelihood of an EF1 or greater tornado affecting the Hydro Ottawa service area over the 30-year time horizon. The September 2019 tornadoes in Ottawa illustrate the damages that such meteorological event can cause to the system and its components if a direct strike occurs. The Hydro Ottawa *After Action Report* of October 18, 2018 summarizes how the utility reacted to this event and recommendations for improvements.

Potential actions to mitigate risks and adaptation to future tornado strikes will be assessed in the next phase of the study.

5.5.1.2



1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-132**

4
5 **EVIDENCE REFERENCE:**

6
7 **OM&A Cost Drivers**

8 Ref. 1: Exhibit 4 / HOL_Attachment 4-1-2(D) / Appendix 2-JB

9 Ref. 2: Exhibit 4 / Tab 1 / Schedule 2 / p. 5 (pdf p. 46)

10
11 **Preamble:**

12 Reference 1 shows that major weather events contributed to \$8.4M in OM&A cost increase
13 (reference 2) in 2023 and the labour strike added another \$5.9M in the same year (the total cost for
14 these categories is \$14.3M). In 2024, the table shows a cost reduction of \$6.5M in 'Other Costs'
15 category. Hydro Ottawa states in reference 2 that the cost reduction of \$6.5M in 2024 reflects the
16 one-time costs from the storms and labour strike in previous year not recurring.

17
18 **QUESTION(S):**

19
20 a) Please explain in detail why the cost reduction from the storms and labour strike in 2024 was
21 only \$6.5M which is less than half of the cost increase of \$14.3M in these two categories in the
22 previous year. Please explain whether the rest of the cost increase (\$7.8M) reflect sustained
23 increased cost of storms or for other reasons.

24
25
26 **RESPONSE(S):**

27
28 The \$6.5 million net cost reduction in 2024 reflects the combined impact of many factors on OM&A
29 costs, many of which are not above the materiality threshold. Table A - 2024 Additional OM&A Cost
30 Drivers below provides an additional layer of detail of the other costs increases in 2024.

1 The labour strike not only incurred its own costs but also forced a pause on a number of expenses
 2 as normal work activities could not be completed during the strike as well as a backlog on many
 3 items that required additional costs in 2024 to catch-up. This included items like distribution
 4 maintenance activities, training and recruiting. Then other costs such as fuel were higher in 2024
 5 versus 2023 as many vehicles were not used during the labour strike.

6
 7 Additionally, other costs increased beyond the OEB's inflation parameters, including those for
 8 compensation, insurance, technology costs, external customer contact centers, and OEB fees.
 9 Finally, additional costs were added to 2024 for recruiting, training, and safety uniforms for the new
 10 positions created that year.

11 **Table A – 2024 Additional OM&A Cost Drivers (\$'000 000s)**

	2024
Reversal of one-time cost incurred in 2023:	
Major Weather Events	\$ (8.4)
Labour Strike	\$ (5.9)
Cost increases in 2024:	
Compensation beyond OEB Inflation parameter	\$ 2.3
Distribution Maintenance	\$ 1.5
Training	\$ 1.1
Technology Costs	\$ 0.7
Consulting	\$ 0.4
Recruiting	\$ 0.4
Fuel	\$ 0.2
Backup Data Center	\$ 0.2
Insurance	\$ 0.2
External customer contact center costs	\$ 0.2
Media Communications	\$ 0.2
OEB Fees	\$ 0.1
Safety Clothing	\$ 0.1
Others	\$ 0.2
Other Costs (Net Impact)	\$ (6.5)

12

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-133**

4
5 **EVIDENCE REFERENCE:**

6
7 Enterprise Asset Management (EAM) System

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 1 / Attachment A / pp. 7-16 (pdf pp. 26-35)

9 Ref. 2: Exhibit 4 / Tab 1 / Schedule 2 / p. 39 (pdf p. 80)

10
11 **QUESTION(S):**

12
13 a) In reference 1, Hydro Ottawa states that EAM system will replace disparate systems with a
14 unified platform, facilitating real-time data collection and condition based monitoring, thereby
15 extending asset longevity and reducing downtime. Please explain the current systems that
16 Hydro Ottawa has been using prior to the implementation of the EAM system.

17 b) Please provide an actual/forecast annual cost for the current systems being used for the 2021 to
18 2025 period.

19 c) Did Hydro Ottawa consider other alternatives to replace the current systems? If so, please
20 explain why the EAM system was chosen and whether it is the most cost-effective option.

21 d) With the efficiency gains through the EAM deployment, has Hydro Ottawa estimated any cost
22 savings associated with switching to the EAM system?

23 i) If so, please provide the estimated cost savings (per year) for the forecast period.

24 ii) Has Hydro Ottawa incorporated the cost savings into this application? If so, please
25 identify where in the application.

26 e) From reference 2, the total EAM system cost in 2026 is \$3.0M which accounts 48% of the total
27 cost increase of \$6.3M in the Engineering & Design OM&A program in 2026. Is there an urgent
28 need to deploy the EAM system in 2026? Please explain.

29 f) Based on Table 4 in reference 1, the implementation cost of EAM is forecast at \$2M per year in
30 2026 and 2027 and is expected to decrease to \$1M in 2028. Please explain why the
31 implementation costs are higher in 2026 and 2027 than in 2028.

1 g) When is the EAM system expected to be implemented in 2026?
 2
 3

4 **RESPONSE(S):**
 5

6 a) The current systems used by Hydro Ottawa consist of a mix of disparate business applications,
 7 spreadsheets, and offline systems, requiring significant manual intervention to compile
 8 information needed for asset management. Section 5.1.1 of Schedule 2-5-4 - Asset
 9 Management Process highlights some of the different systems used to store its technical,
 10 testing, inspection, and maintenance information and Table A below summarizes the system by
 11 asset management function.
 12
 13

Table A - Asset Management Functions and Current Systems in Use

Business Function	Application / Technology
Finance	Oracle JDE 9.2
Procurement	Oracle JDE 9.2
Supply Chain	Oracle JDE 9.2
Metering and Billing	Oracle Customer Care & Billing 2.7
Customer Relationship Management	Salesforce CRM
Human Capital Management	Workday HCM
Field Service Management	Salesforce FSL
GIS	Hexagon GIS
Outage Management System	Hexagon OMS
Work Estimation	ERTH Quadra
Asset Investment Decisions	Copperleaf C55
Asset Test Data Management	PowerDB and Spreadsheets
Asset Maintenance Records	Aspen Relay DB, Spreadsheets and Oracle JDE 9.2
Asset Record Management	Spreadsheets, GIS and Oracle JDE 9.2
Asset Lifecycle Management	Spreadsheets, Copperleaf PA
Work Management	Spreadsheets, Salesforce CRM, Salesforce FSL, Oracle JDE 9.2 and Workday HCM
Asset Project Management	Spreadsheets, Microsoft Project, Copperleaf Portfolio, Smartsheet
Asset Analysis	Spreadsheets, Copperleaf PA and Oracle JDE 9.2
Asset Investment Planning	Spreadsheets, Copperleaf PA, Copperleaf Portfolio

1 b) The systems listed in part a) above are a mix of capital and OM&A software solutions which are
2 used only in part for asset management. A sizable portion of asset management processes
3 reside within spreadsheets and are manually managed. As a result, Hydro Ottawa is not able to
4 provide annual EAM equivalent costs without undertaking significant effort to identify and cost
5 each of these disparate elements. Hydro Ottawa notes that the majority of the software
6 technology in part a) are not anticipated to be eliminated through introduction of the EAM
7 platform as they are used for more than just EAM functions.

8
9 c) Yes, Hydro Ottawa did consider the alternative of continuing to manage its assets using its
10 current mix of disparate systems, manual processes, and spreadsheets. However, a 2022
11 assessment concluded that this approach would not be a viable long-term option, especially
12 given the planned growth in the capital program. The assessment found that continuing with the
13 current system would likely require more manual intervention and additional headcount in the
14 long run, and would not effectively address the challenges of fragmented data and technology
15 limitations.

16
17 As a result, Hydro Ottawa determined that a modern Enterprise Asset Management (EAM)
18 system is the only way to effectively centralize critical asset information, automate maintenance
19 workflows, and provide the comprehensive data analytics necessary for optimizing performance,
20 extending asset lifecycles, and ensuring regulatory compliance. The company is committed to
21 selecting the most cost-effective EAM platform, and the 2025 roadmap is being developed to
22 inform the evaluation and selection of the technology for a phased implementation beginning in
23 2026.

24
25 d) While the EAM project is expected to generate future cost savings through efficiency gains,
26 these savings have not yet been quantified and incorporated into this application. The primary
27 purpose of the EAM project is not to achieve short-term cost savings, but rather to address
28 critical operational gaps and ensure the long-term reliability and efficiency of Hydro Ottawa's
29 infrastructure.

1 As noted in the evidence, Hydro Ottawa's asset portfolio is projected to grow significantly by
2 2030, and a 2022 assessment identified that the current manual processes, fragmented data,
3 and technology limitations impede efficient management and compliance. The EAM project is a
4 strategic response to these challenges.

5 The project is currently in the initial phase, with a roadmap being developed in 2025. This
6 roadmap will include a comprehensive evaluation of potential EAM technologies, with a key
7 focus on cost-effectiveness. Until a specific EAM system is chosen and the roadmap is
8 complete, it is difficult to quantify the precise cost savings. However, the anticipated benefits,
9 such as optimized asset performance, reduced operational and maintenance costs, and
10 improved regulatory compliance, are the core drivers of this project and are expected to deliver
11 significant long-term value.

12

13 i) See response to part d).

14

15 ii) See response to part d).

16

17 e) Yes, there is an urgent need to commence the EAM project in 2026 after completion of the
18 roadmap and planning exercise in 2025. The primary purpose of this project is to ensure Hydro
19 Ottawa's infrastructure remains reliable and efficient, meeting the demands of a growing service
20 territory and a dynamic energy landscape. The modernization of our grid and electrification
21 initiatives will see a significant increase in the number of field assets.

22

23 As noted in EAM evidence (Ref 1), a 2022 assessment highlighted critical gaps—manual
24 processes, technology limitations, and fragmented data—reducing efficient management,
25 impending further improvements and ISO audit compliance in the asset management realm.
26 These challenges must be addressed to efficiently scale asset management operations while at
27 the same time striving for cost effectiveness. The 2025 roadmapping exercise is a crucial first
28 step and will help inform the rationalization of legacy applications, eliminate spreadsheet
29 eco-systems, remove manual intervention, improve asset management processes, collaboration
30 and data quality.

- 1 f) The implementation costs of EAM are higher in 2026 and 2027 because the project “heavy
2 lifting” will occur in those years. These activities include pre-work activities, core platform
3 deployment, workshops and process re-engineering, data cleanup, data conversion, system
4 integrations, testing activities and organizational change management. Table 3 within
5 Attachment 4-1-1(A) - Transition to Cloud Computing lists out these cost and time-intensive
6 activities.
7
- 8 g) The EAM implementation will run from 2026 through 2028. Please refer to Table 3 - Proposed
9 Timeline of the EAM Program in Attachment 4-1-1(A) - Transition to Cloud Computing.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-134**

4
5 **EVIDENCE REFERENCE:**

6
7 Testing, Inspection, and Maintenance OM&A Program
8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 10-19 (pdf pp. 51-60)

9
10 **QUESTION(S):**

11
12 a) Table 5 in the reference shows a comparison of asset/activity descriptions for the Testing
13 Inspection & Maintenance Activity (Base Program) and the 2026-2030 Program Enhancements.

14 For each of the asset/systems category, please provide the following:

- 15 i) Please provide expected cost increases or decreases by implementing the program
16 enhancements in 2026 compared to the base program.
17 ii) Please provide the main drivers of cost increases/decreases in a) i.
18 iii) The program cost is forecast to increase by \$6.1M in 2026. Please explain how Hydro
19 Ottawa determined the cost for each asset/system category in a) i.
20 iv) Did Hydro Ottawa perform any analysis to determine whether there is any future cost
21 saving that would be realized to offset the cost increases from the program
22 enhancements? If so, please provide any supporting documents.

23 b) Hydro Ottawa states that historical reliability data indicates a slight increase in equipment
24 failures since 2021, particularly in overhead assets and it has experienced a relatively high
25 number of outages each year due to overhead switches, underground transformers and cables,
26 which do not correlate to the condition information and resulting health indices. Please explain
27 what caused these equipment failures.

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11

RESPONSE(S):

- a) The requested information for each asset/systems category is detailed below:
- i) Expected cost increases by implementing the program enhancements in 2026 compared to the base program total \$5.6M, see column 2 of Table A below. Any programs without enhancements in 2026 show 'N/A' as there is no change in costs attributable to changes in program scope.
 - ii) For the main drivers of cost increases in a) i, see column 3 of Table A.

Table A - Program Enhancement Costs in 2026

Asset/Systems	Cost Increase/Decrease (in \$)	Main Driver
Cable Chambers	\$ 55,000	General contractor pricing increase and additional duty pay charged for inspecting critical locations such as the middle of major roadways and restricted areas. Proposed improvements towards exploring better inspecting tools/technologies
Distribution Poles	N/A	Drone-based inspection program included as a part of the Overhead Lines and Assets (Overall) enhancement costs.
Overhead Insulators	N/A	No program enhancement in 2026
Overhead Lines and Assets (Overall)	\$ 490,000	Drone inspection of overhead lines and assets (including overhead switches and overhead transformers)
Overhead Switches	N/A	Drone-based inspection program included as a part of the Overhead Lines and Assets (Overall) enhancement costs.
Overhead Transformers	N/A	Drone-based inspection program included as a part of the Overhead Lines and Assets (Overall) enhancement costs.
Underground Equipment	\$ 90,000	General increase to capture visual inspection and infrared (IR) information related to Hydro Ottawa-owned vault equipment and increasing the frequency of inspection for select vault equipment in a degraded

Asset/Systems	Cost Increase/Decrease (in \$)	Main Driver
		condition
Underground Transformers	N/A	No program enhancement in 2026
SCADA Devices	\$ 60,000	Expanded maintenance program for FCIs and inspecting DA Devices
Underground Lines & Feeders	\$ 245,000	Increased program for formal cable testing to perform Very Low Frequency Tan-Delta, PD and Time Domain Reflectometry test procedures on polymeric distribution cables to prioritize relevant renewal/refurbishment activities.
Customer Equipment	N/A	No program enhancement in 2026
Underground Switchgear	N/A	No program enhancement in 2026
Underground Switchgear & Transformers Inspection	\$ 60,000	Increased inspection data capture down to the component level and general contractor price increase
Battery Energy Storage Systems (BESS)	N/A	Not applicable in 2026
Third Party Non Wire Alternative Solutions	\$ 2,800,000	Third party operating and maintenance of non-wire alternative solutions
Overall Distribution	\$ 1,800,000	Proposed funding to introduce improvements to maintenance programs/practices based on changing/evolving needs. Exploring opportunities include automating/improving the capture of inspection information, enhanced condition assessment based on artificial intelligence, etc.

Asset/Systems	Cost Increase/Decrease (in \$)	Main Driver
TOTAL	\$ 5,600,000	

1

2

3

iii) The maintenance program cost determination basis by asset/system is presented in Table B.

1

Table B - Program Cost Determination

Asset/Systems	Cost Determination Basis
Cable Chambers	Based on Contractor Pricing and additional duty charges to be paid for inspecting critical locations. Improvements towards exploring better inspection tools/technologies
Distribution Poles	Based on Contractor Pricing (for drone operator and software platform provider for results/analytics)
Overhead Insulators	N/A
Overhead Lines and Assets (Overall)	Based on Contractor Pricing (for drone operator and software platform provider for results/analytics)
Overhead Switches	Based on Contractor Pricing (for drone operator and software platform provider for results/analytics)
Overhead Transformers	Based on Contractor Pricing (for drone operator and software platform provider for results/analytics)
Underground Equipment	Based on Hydro Ottawa crew involvement and additional budget for comprehensive assessment
Underground Transformers	N/A
SCADA Devices	Based on Hydro Ottawa crew involvement and additional budget for maintaining FCIs
Underground Lines & Feeders	Based on Contractor Pricing for advanced cable testing and switching/isolation
Customer Equipment	N/A
Underground Switchgear	N/A
Underground Switchgear & Transformers Inspection	Based on Contractor Pricing
Battery Energy Storage Systems (BESS)	Not applicable in 2026
Non-Wires Programming & System IntegrationT	Anticipated Contractor Pricing for managing third-party NWS
Maintenance Enhancements and Innovation	Based on estimated engineering, technology, software and implementation costs for improving inspection data capture through image recognition, leveraging machine learning for regional analysis, and automating station inspections.

1 The remaining projected cost increase of \$0.5M for 2026 is related to projected contractor
2 pricing increases, reactive maintenance spending and general inflation, not specific program
3 enhancements.

4
5 iv) The cost savings that can be realized by investing in the maintenance program
6 enhancements are embedded in Hydro Ottawa's investment priority/strategy of
7 managing deteriorating asset infrastructure. By 2030, an estimated \$862M would be
8 needed to replace all Hydro Ottawa assets projected to be in degraded condition.
9 However, this level of investment is not feasible given other critical financial priorities
10 such as growth, electrification, grid modernization, and resilience. Consequently, Hydro
11 Ottawa is proposing a \$261M investment over the next five years (2026-2030). While
12 this will result in an increase in the overall percentage of degraded assets, Hydro Ottawa
13 shall strive to maintain current service levels through 2026-2030 based on a
14 multi-faceted risk-mitigation strategy:

- 15 ● **Improved Risk Prioritization:** Leveraging predictive analytics to better identify and
16 intervene on the most critical assets.
- 17 ● **Enhanced Inspection and Maintenance Programs:** Enhanced distribution and
18 stations testing, inspection, and maintenance programs are fundamental to Hydro
19 Ottawa's asset renewal strategy, based on the condition information obtained from
20 the corresponding programs.
- 21 ● **Advanced Inspection Technologies:** To bolster condition data accuracy, Hydro
22 Ottawa will deploy cutting-edge technologies, including drone inspections for
23 overhead assets. These technologies will enable highly targeted maintenance
24 interventions and more precise asset health assessments. Further information on
25 Hydro Ottawa's investment priorities around renewing deteriorating infrastructure can
26 be found in Section 2.3.2 of Schedule 2-5-1 - Distribution System Plan Overview.

27
28 b) The primary causes of overhead switch failures that led to outages between 2019 and 2023
29 were thermal anomalies like burnt switches/cutouts and physical damage such as broken
30 porcelain switches. Failures of this nature are typically due to age and occur once the overhead
31 switch has reached its Typical Useful Life (TUL). With a large percentage of overhead switches

1 reaching TUL by 2035 (as outlined in Section 3.3.4 of Schedule 2-5-7 - System Renewal
2 Investments), Hydro Ottawa is enhancing the inspection program to gain a deeper
3 understanding of overhead switch and transformer conditions, as well as recommending
4 drone-based inspections from 2026-2030 to gather more precise data. These enhancements
5 will aid in identifying damage or deficiencies, allowing Hydro Ottawa to plan for replacement
6 before an outage occurs.

7
8 The primary causes of underground transformer failures that lead to outages between 2019 and
9 2023 were corrosion and leaks, leading to electrical failures. Degradation mechanisms that lead
10 to cable failures are difficult to detect and predict. To this end, Hydro Ottawa advanced its
11 testing methodologies and analyzed the regional failure trends in select impacted circuits
12 through a 2024 cable testing pilot. This pilot utilized Very Low Frequency Tan-Delta, Partial
13 Discharge (PD), and Time Domain Reflectometry (TDR) test procedures on polymeric
14 distribution cables. The pilot's results indicated localized degradation patterns, including
15 insulation deterioration and significant cable degradation, enabling Hydro Ottawa to plan
16 targeted interventions. Hydro Ottawa's proposed enhancements to its Underground Lines and
17 Feeders program builds on the cable testing pilot findings and will allow Hydro Ottawa to gain a
18 better understanding of regional failure trends and outage causes, allowing for more targeted,
19 risk-based intervention.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-135**

4
5 **EVIDENCE REFERENCE:**

6
7 Testing, Inspection, and Maintenance OM&A Program – Drone-based Inspection
8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 10-19 (pdf pp. 51-60)

9
10 **QUESTION(S):**

- 11 a) Has the inspection cycle changed for the IR Scanning of equipment from the ground to using a
12 drone?
- 13 b) What permits are required to operate drones for business purposes within the City of Ottawa /
14 Municipality of Casselman (municipal, provincial, federal)? Please provide the following
15 information as part of this response:
- 16 i) Has Hydro Ottawa been through the process of obtaining these permits?
- 17 ii) How much of the service area is located in areas where permits will not be allowed?
- 18 c) Will Hydro Ottawa continue with the ground scan in areas where the drone scan is not
19 permitted?
- 20 d) Will Hydro Ottawa personnel or its contractor(s) be performing the drone scan?
- 21 e) What additional information will be collected with the drone scan and how it will be used?
- 22 f) Hydro Ottawa states that it “will pilot drone inspections in 2025 to gather more accurate visual
23 and infrared scan information on overhead distribution assets, as compared to ground-based
24 inspections. Results from this initiative will inform the basis of the program commencing in
25 2026.” Please provide more detail on the results from the drone-based inspection program to
26 date.
- 27 g) What are the total estimated capital and OM&A costs of the drone-based inspection program
28 per year from 2026 to 2030?
- 29 h) Did Hydro Ottawa consider other cost-effective options for advanced inspection technologies
30 besides drone-based inspection? If so, please explain whether the drone inspection technology
31 is the most cost-effective option compared to other advanced inspection technologies that were

1 considered or not. If not, please explain why Hydro Ottawa chose the drone-based inspection
2 technology.

3
4
5 **RESPONSE(S):**

6
7 a) No, the inspection cycle for infrared (IR) scanning of equipment has not changed with the
8 transition from ground-based methods to drone usage, however Hydro Ottawa is piloting the
9 usage of drones and, if successful, will begin employing drones for IR scanning during the test
10 period. If drones are leveraged, Hydro Ottawa will uphold the existing three-year cycle for both
11 visual inspections and IR scanning of overhead equipment via drones. This approach ensures
12 continued adherence to OEB Appendix C: Minimum Inspection Requirements.

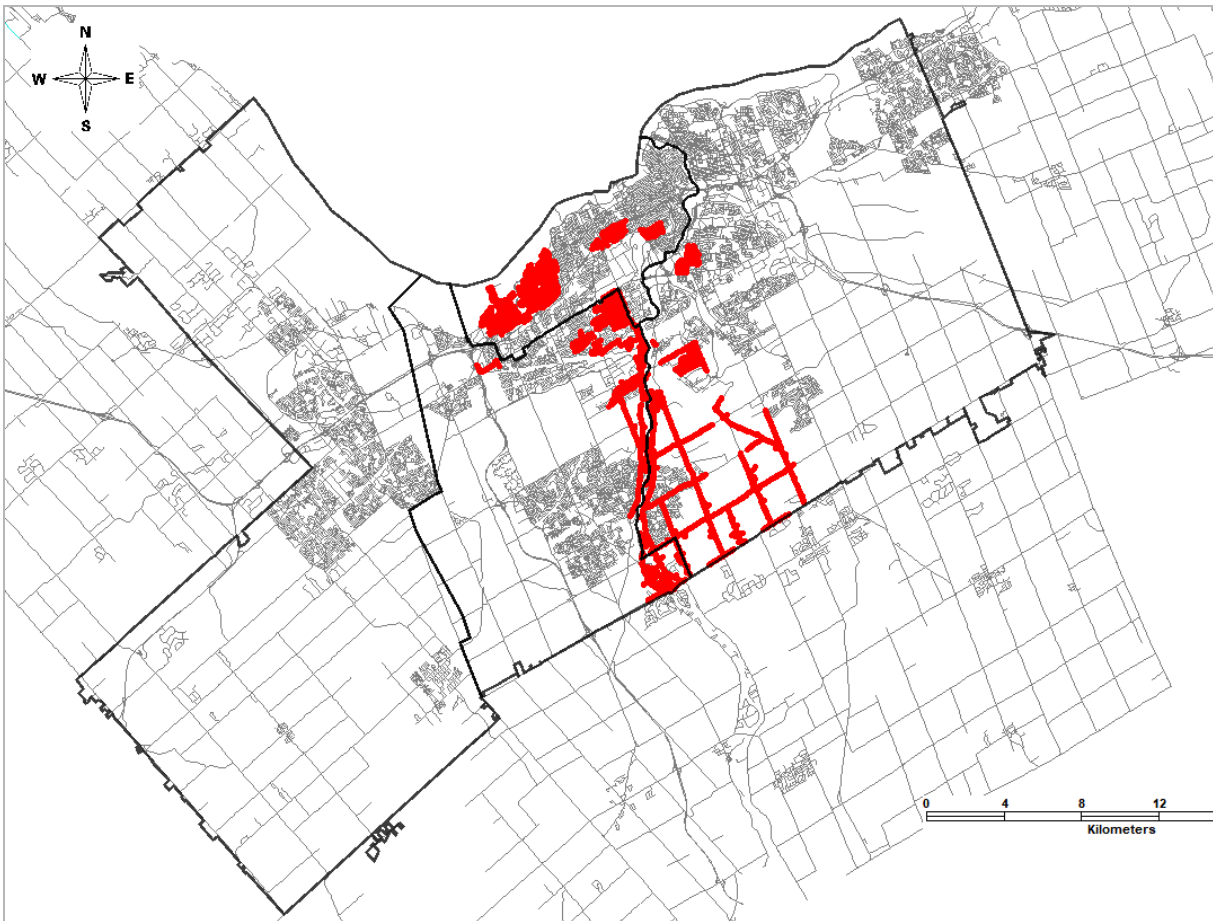
13
14 b) Hydro Ottawa's overhead assets located in restricted airspace and No-Fly Zones will require a
15 Special Flight Operations Certificate (SFOC) to allow for drone operation in these regions. For
16 flights conducted in other controlled airspace, Nav Canada flight authorizations need to be
17 submitted and approved. They indicate operation dates, equipment and location details, flight
18 boundaries and altitudes, and the nature of work.

19
20 i) Hydro Ottawa is working with a certified drone service provider who will obtain the
21 permits required prior to the inspection. The drone service provider has specific
22 expertise and certification in:

- 23 ● Standing, nationwide SFOC for RPAS in Canada (pre-2019)
- 24 ● Advanced Operator Certification & Transport Canada (TC)
- 25 ● Accredited Flight Reviewers
 - 26 ○ Previously on TC Mirror Committee
 - 27 ○ Approved BVLOS applications (2)
 - 28 ○ Approved SFOCs (5)
- 29 ● Certified in US also (FAA pt. 107)
- 30 ● Professor/Instructor experience & keynote/conference speakers

1 ii) There are no regions within the service territory where permits cannot be sought. The
2 areas highlighted (in red) in Figure A, are within restricted areas, and the drone service
3 provider is in the process of obtaining the permits on behalf of Hydro Ottawa prior to the
4 drone inspection.
5

6 **Figure A - Regions with most overhead assets in restricted areas (highlighted in red)**



7
8
9 c) If permits are not obtained for the restricted areas, Hydro Ottawa will proceed with ground scans
10 and will continue to collaborate with the drone service provider to formalize the permit
11 acquisition process for restricted zones. Should drone inspection remain unfeasible in specific
12 areas, Hydro Ottawa will conduct ground-based inspections.

1 d) Hydro Ottawa will utilize certified drone service providers for inspections, ensuring line-of-sight
2 is maintained. Hydro Ottawa personnel will provide field operations support and oversight
3 throughout the drone inspection process.

4
5 e) As a part of the drone inspection, the plan is to inspect overhead distribution equipment using
6 drones (excluding conductors) at every pole (as present/applicable):

- 7 ● Inclusive of polemount transformers, switches, fuses, reclosers, line insulators, surge
8 arresters, potheads, riser cable terminations and line hardware (e.g., conductor sleeves,
9 fittings, splices, ampacts etc.)
- 10 ● Visual Inspection and IR scanning to be performed

11
12 Pre-defined inspection parameters (provided by Hydro Ottawa) are to be reported at every pole,
13 specific to the individual distribution equipment present. This information will be used for
14 long-term health indexing and asset condition assessment.

15
16 Sample pre-defined inspection parameters (for polemount transformers):

- 17 ● Presence of loose wire connections
- 18 ● Extent of rust/corrosion
- 19 ● External short circuit marks
- 20 ● Presence of hotspots

21
22 f) Hydro Ottawa is currently finalizing the IT and cyber security verification/reviews of the drone
23 service provider and the associated software vendor to ensure that there are no vulnerabilities.
24 Following this review, the pilot is planned for Q3/Q4 2025. However, in 2025, Hydro Ottawa has
25 effectively utilized drones within confined station environments to gather precise 115 kV
26 lightning arrester nameplate data and detailed imagery. The use of drones has proven to be
27 successful in verifying visual conditions that were previously difficult to assess from ground
28 level.

29
30 g) There are only OM&A costs associated with the drone inspection program and this is
31 highlighted in Table A. More information regarding the basis for cost determination and the

1 scope of the base program increase through the use of drones is discussed in Hydro Ottawa's
2 response to the interrogatory question 4-Staff-134 part (a).

3
4

Table A - Drone Inspection Costs (\$'000s)¹

	2026	2027	2028	2029	2030
Drone Inspection (OM&A)	\$ 1,107	\$ 1,164	\$ 1,224	\$ 1,288	\$ 1,354

5

6 h) Hydro Ottawa has explored existing technologies to enhance the accuracy of inspection data for
7 overhead distribution assets. This involved active participation in utility groups and forums, such
8 as Electricity Canada, CEATI, and the EDA, to identify best practices and analyze peer utility
9 case studies. Drones emerged as the most suitable inspection method for capturing relevant
10 condition information on these assets.

11

12 As detailed in Section 3.1.1 - 2026-2030 Business Priorities under Schedule 4-1-2 - Operations,
13 Maintenance and Administration Program Costs, Hydro Ottawa had also observed reliability
14 issues stemming from overhead apparatus failures, often linked to insufficient condition
15 assessments from ground-based inspections. To gather additional visual data from inspections,
16 an alternative option to drone inspection is to do the inspection from a bucket truck so that
17 additional details can be observed that cannot be seen from the ground. To enable this process
18 a number of factors would need to be considered: potential for work protection for crew safety,
19 traffic control plans and support including set up and tear down, minimum two-member crew and
20 bucket truck, appropriate access to every pole, set up and tear down of equipment and vehicles
21 at each pole, etc. Consequently, drones were identified as the most appropriate option to
22 improve Hydro Ottawa's understanding of the actual condition of overhead assets and enable
23 their effective management.

¹ 2027-2030 Test Years are forecast using the Custom Revenue OM&A Factor discussed in Schedule 1-3-1 Rate Setting Framework.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-136**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 2 / Tab 5 / Schedule 8 / p. 49 (Table 2) (pdf Exhibit 2 Part 4, p. 413)

8 Ref. 2: Exhibit 4 / Tab 1 / Schedule 2 / p. 19 (pdf p. 60)

9 Ref. 3: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / p.17 (pdf p. 203)

10 Ref. 4: Exhibit 4 / Tab 1 / Schedule 3 / p. 2 (pdf p. 113)

11 Ref. 5: Exhibit 1 / Tab 4 / Schedule 1 / p. 44 (pdf Exhibit 1 Part 2, p. 44)

12
13 **Preamble:**

14 The following high-level NWS cost breakdown was provided by Hydro Ottawa:

15

Capital	
Non-Wires Capital Upgrades	\$61.2 M
Expense	
Other Revenue Expenses – NWS	\$10.0 M
Non-Wires Maintenance	<u>\$13.4 M</u>
Total Proposed NWS Spending (excluding external funding)	\$84.6 M

16
17 Hydro Ottawa notes that CDM staffing may continue into 2026-2030, but the CDM activities
18 proposed in this application are beyond the scope of IESO’s eDSM framework. Hydro Ottawa plans
19 on adding 177 new positions between 2024-2030.

20
21 Hydro Ottawa notes that its testing, inspection, and maintenance program will be expanded to
22 include a new program for BESS and monitoring services of third-party NWS. This includes a \$2.8M
23 annual program that leverages internal and external resources to monitor, control, dispatch, and
24 predict demand.

- 1 QUESTION(S):
- 2 a) Please confirm if the total NWS funding amount requested (\$84.6M) includes staffing costs
- 3 associated with each of the NWS initiatives.
- 4 b) Please clarify the OM&A cost and the number of staff associated with each NWS initiative. How
- 5 much is attributable to existing CDM/eDSM as opposed to new NWS initiatives? Refer to Table
- 6 5 below for guidance.
- 7 c) Please clarify how many of the 177 new positions are attributable to NWS and DERs.
- 8 d) Please confirm if and how the OM&A costs associated with staffing and NWS integration have
- 9 been considered in Hydro Ottawa’s assessment of each NWS initiatives’ cost effectiveness.

10

11

Table 5: Staffing Breakdown (\$ and #) by NWS Initiative

NWS Initiative	# Staff		\$ Staffing Cost	
	Existing	New	Existing	New
NWCSP – Save on Energy Retrofit Adder				
NWCSP –Residential DR				
NWCSP – Commercial DR				
NWCSP – Solar PV and Energy Storage				
BESS (West 28 kV)				
BESS (Bells Corners/ Bayshore 8 kV)				
BESS (Casselman 8 kV)				
BESS (Core 13 kV, West 13 kV)				
Etc. – Add for each individual NWS program				

12

13

14 **RESPONSE(S):**

15

16 a) Hydro Ottawa confirms that the \$84.6M listed includes internal labour costs associated with

17 these programs.

18

19 b) The breakdown of OM&A costs associated with the NWS Maintenance Program is provided in

20 Table A below. Hydro Ottawa does not forecast or attribute new headcount in terms of specific

21 initiatives or assets, such as NWSCP, DERs, or BESS, but rather by work program and driver as

22 described in Section 3 of Schedule 4-1-3 - Workforce Staffing and Compensation, and Section

23 Section 3.1.1 and 3.1.2 of Attachment 4-1-3(C) - Workforce Growth. However, these are one of

1 the multiple drivers attributing to headcount increases in Metering, Engineering & Design,
 2 Distribution Operations as shown Section 3.1.1.1, 3.1.2.2, 3.1.2.3, and 3.1.2.4 in Attachment
 3 4-1-3(C) - Workforce Growth. In 2024, Hydro Ottawa added 22 staff for Customer Connection &
 4 Capacity Program Growth (indirectly supporting NWS & DERs), 4 positions for DER & Capacity
 5 Connection Request Complexity (directly supporting, though not exclusively dedicated to NWS
 6 & DERS), and 10 positions for Grid Modernization (directly supporting, though not exclusively
 7 dedicated to NWS & DERS).

8
 9 Hydro Ottawa plans to add an incremental 177 positions, 127 between 2026-2030. Though
 10 NWS & DERs are not directly attributable to new positions, both form part of the multiple drivers
 11 associated with 2026-2030 headcount growth as per Section 3.1.2 of Attachment 4-1-3(C) -
 12 Workforce Growth. Furthermore, as some initiatives will inherently have a term and be shorter in
 13 nature, as part of its regular planning cycles, Hydro Ottawa will leverage temporary employee
 14 arrangements as required (as noted in Section 3 of Schedule 4-1-3(B) - Workforce Planning
 15 Strategy) as a strategy to ensure programming is adequately staffed.

16
 17 **Table A - Non-Wires Programming & System Integration 2026 (\$'000 000s)**

Cost Type	Test Year
	2026
Labour	\$ 2.7
Materials	\$ 0.0
Overheads	\$ 0.0
Other	\$ 0.1
Sub-total	\$ 2.8
Labour Recovery	\$ (0.6)
Total	\$ 2.2

18
 19
 20 c) Please see response to part (b).

- 1 d) Hydro Ottawa has considered OM&A costs associated with staffing when completing the
- 2 Benefit-Cost Analysis (BCA) provided in Attachment 2-Staff-67(A) - Benefit-Cost Analysis
- 3 Summary Report that are completed for future regions will likewise consider staffing within
- 4 OM&A costs. Further to part b), NWS are considered as an input to multiple drivers that
- 5 substantiate Hydro Ottawa request for headcount between 2024 and 2030.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-137**

4
5 **EVIDENCE REFERENCE:**

6
7 OM&A Program Costs and New Positions by Program Cost

8 Ref. 1: Exhibit 4 / HOL_Attachment 4-1-2(B) / Tab App.2-JC_OMA Programs and Exhibit 4 / Tab 1 /
9 Schedule 2 / pp. 18-66 (pdf pp. 59-107)

10 Ref. 2: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / Table 1 / p. 3 (pdf p. 189)

11 Ref. 3: Exhibit 4 / Tab 1 / Schedule 3 / Attachment A / Table 10 / p. 16 (pdf p. 144)

12
13 **Preamble:**

14 In reference 1, Hydro Ottawa provides OM&A program costs and variance analysis with
15 explanations for the cost increases which include additional costs associated with new positions.

16
17 Reference 2 shows new positions forecast for 2024 – 2030 without vacancy assumptions.

18
19 Reference 3 shows the number of FTEs (Appendix 2-K) which is derived by applying a vacancy rate
20 to new positions.

21
22 OEB staff notes that Hydro Ottawa’s explanations for the cost increases resulting in new positions
23 being added (reference 1) are based on the forecast new positions forecast prior to the vacancy
24 rate of 8% being applied (shown in reference 2).

25
26 **QUESTION(S):**

27
28 a) Are the OM&A costs associated with new positions in reference 1 derived based on forecast
29 new positions shown in reference 2 or the number of FTEs in reference 3?

30 i) If the costs are derived based on new positions in reference 2, please provide a rational
31 for this approach.

1

2 **RESPONSE(S):**

3

4 a) The OM&A costs for all positions, including the new ones mentioned in reference 1, are derived
5 from the vacancy adjusted FTEs in Reference 3.

6 i) Not applicable given the response to part a) above.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-138**

4
5 **EVIDENCE REFERENCE:**

6
7 Underground Locates OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / Tables 8 and 9 / pp. 24-25 (pdf pp. 65-66)

9
10 **QUESTION(S):**

11
12 a) Please update Tables 8 and 9 to reflect 2024 actual data.

13 b) OEB staff is not able to reconcile the locate costs between Table 8 and Table 9.

14 Please provide additional calculations and explanations to reconcile the locate costs between
15 the two tables. Please provide the following information in the explanations:

16 i) For Table 9, does the “Average Cost per Locate” represent the total cost per locate
17 which includes both internal and external cost?

18 ii) For Table 9, please confirm that the “Total External Locate Deliver Services Costs” does
19 not include internal locate costs.

20 iii) For Table 9, is Ontario One Call cost included in the calculations?

21 c) Please explain why the underground locates expenditures are forecast to increase to \$6,027 in
22 2026 from \$5,285 in 2025 (Table 8) when the number of locates is forecast to remain
23 unchanged at 61,410 in 2026 (Table 9) compared to 2025, and the average cost per locate is
24 forecast to decline to \$86.16 in 2026 from \$87.40 in 2025 (Table 9).

25
26
27 **RESPONSE(S):**

28
29 a) Please see Table A for the 2024 update to Table 8 and Table B for the 2024 update to Table 9.

1 **Table A - Underground Locates Variances 2021-2026 (\$'000s)**

	Historical Years				Bridge Year	Test Year	CAGR
	2021	2022	2023	2024	2025	2026	
Expenditures	\$ 3,273	\$ 3,538	\$ 3,389	\$ 4,036	\$ 5,285	\$ 6,027	13.0%
Variance (\$)	-	\$ 265	\$ (149)	\$ 647	\$ 1,249	\$ 742	-
Variance (%)	-	8.1%	(4.2%)	19.1%	30.9%	14.0%	-

2
 3 Note that Table B uses corrected locate (segment) numbers to include all locate requests,
 4 whether they are fulfilled by field locates or office clears. This brings the table into alignment
 5 with other discussions of the Underground Locates program, including the productivity savings
 6 discussed in Section 3.1.3 of Schedule 1-3-4 - Facilitating Innovation and Continuous
 7 Improvement.

8
 9 **Table B - Cost per Locate 2021-2026**

	Historical Years				Bridge Year	Test Years
	2021	2022	2023	2024	2025	2026
Number of Locates (segments)	71,574	56,532	58,558	56,263	66,599	66,599
Average Cost per locate (\$)	\$ 32.89	\$ 49.40	\$ 58.94	\$ 64.57	\$ 80.59	\$ 79.45
Total External Locate Deliver Services Costs (\$000s)	\$ 2,631	\$ 3,015	\$ 3,622	\$ 3,716	\$ 5,443	\$ 5,399
Less: Inspections (\$000s)	\$ (277)	\$ (222)	\$ (171)	\$ (83)	\$ (76)	\$ (108)
Less: amounts in DVA accounts due to Bill 93	-	-	\$ (738)	\$ (271)	\$ (1,645)	-
Net Costs (\$000s)	\$ 2,354	\$ 2,793	\$ 2,714	\$ 3,362	\$ 3,722	\$ 5,291

10
 11 b) See Table C for a reconciliation of the figures in Tables 8 and 9.
 12
 13 Table 8 shows the net expenditures of the Underground Locates program, whereas Table 9
 14 shows only the external labour costs. The difference between the two values is due to the
 15 internal labour and burden costs. Hydro Ottawa over estimated 2025 internal labour in this

1 program, which does not have an impact on the total OM&A for 2025 and was corrected in
 2 2026.

3 **Table C - Reconciliation of Total Costs to External Costs (\$'000s)**

	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Net costs (Table 9)	\$ 2,354	\$ 2,793	\$ 2,714	\$ 3,362	\$ 3,722	\$ 5,291
Add: inspection costs	\$ 277	\$ 222	\$ 171	\$ 83	\$ 76	\$ 108
Add: internal labour	\$ 533	\$ 408	\$ 367	\$ 458	\$ 1,328	\$ 458
Add: burden costs	\$ 109	\$ 116	\$ 137	\$ 134	\$ 160	\$ 170
Total Expenditures (Table 8)	\$ 3,272	\$ 3,538	\$ 3,389	\$ 4,036	\$ 5,285	\$ 6,027

4
 5 i) No, Table 9 shows external costs only.

6
 7 ii) Confirmed, Table 9 does not include internal locate costs.

8
 9 iii) Yes, Ontario One Call is included in Table 9.

10
 11 c) The increase in total underground locate expenditures in 2026 without an increase in the
 12 forecast number of locate requests is due to the closure of the Getting Ontario Connected Act
 13 (GOCA) variance account at the end of 2025. The entirety of the expected costs will be
 14 recorded in the expenditure accounts for the forecast period.

15
 16 The average cost per locate is anticipated to decrease slightly in 2026 because of the budget
 17 methodology used to calculate forecasted costs, which uses averages of prior years as the
 18 basis for the calculations at a certain point in time. The decrease in 2026 amounts to a roughly
 19 2% difference from 2025, which can be attributed to the timing of the historical averages.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-139**

4
5 **EVIDENCE REFERENCE:**

6
7 Vegetation Management OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 19-22 (pdf pp. 60-63)

9 Ref. 2: Exhibit 1 / Tab 3 / Schedule 4 / p. 23 (pdf p. 543)

10 Ref. 3: Exhibit 1 / Tab 3 / Schedule 4 / p. 28 (pdf p. 548)

11
12 **QUESTION(S):**

13
14 a) Hydro Ottawa states that the program includes Emergency Vegetation Management to respond
15 to storms or imminent safety threats as well as the removal of trees infested with invasive
16 species. Please provide the actual amounts spent and budgeted for Emergency Vegetation
17 Management each year from 2021 to 2026.

18 b) In reference 1, Hydro Ottawa states that it plans to continue to leverage the use of Overstory, a
19 software solution for optimizing vegetation management practices and states that the
20 implementation of the Overstory solution will facilitate precise risk assessment. Reference 3
21 states that in 2023 Hydro Ottawa implemented Overstory that enhances efficiency. Please
22 provide the following.

23 i) The statements above about the timing of the implementation of Overstory appear to
24 contradict each other. Has Overstory been implemented already? If so, when? If not,
25 when will it be implemented?

26 ii) Table 2 in reference 2 shows no productivity benefits for the 2021-2025 period. If
27 Overstory was implemented in 2023, please explain why there are no productivity
28 benefits associated with this period.

29 iii) Please provide an annual subscription cost of this software from the implementation date
30 to the end of 2026.

- 1 c) Hydro Ottawa states that the majority of tree trimming is performed by third-party contractors
2 whose costs continue to rise. Please also provide the following:
- 3 i) Please explain the procurement process by which Hydro Ottawa determined the
4 third-party contractors.
- 5 ii) Please provide an annual actual/forecast tree trimming cost performed by third-party
6 contractors from 2021 to 2026.
- 7 d) Are there any new positions forecast under the Vegetation Management program in 2024, 2025,
8 and 2026? If so, please indicate how many as well as provide job titles and a brief description of
9 job responsibilities.
- 10 e) Table 7 in reference 1 shows the program cost increased by \$2.9M (131%) from \$3.8M in 2021
11 to \$6.7M in 2022 due primarily to the Derecho storm. Table 7 also shows that although the costs
12 decreased in 2023 from 2022, they still remained high, ranging from \$5.8M to \$6.3M from 2023
13 to 2026. Hydro Ottawa states several factors including severe weather, high tree coverage, and
14 inflationary pressures (page 22 of reference 1) necessitate the proposed annual spending level.
15 Please provide the Vegetation Management Program cost breakdown per year from 2021 to
16 2026 to demonstrate how the forementioned factors above have kept the programs cost
17 relatively high since 2022.

18
19

20 **RESPONSE(S):**

21
22
23
24

- a) Table A lists the actual and budgeted spend for Emergency Vegetation Management, by year,
for 2021-2026.

25 **Table A - Emergency Vegetation Management Spend 2021-2026 (\$'000s)**

26
27
28
29

	Historical Years				Bridge Year	Test Year
	2021	2022	2023	2024	2025	2026
Emergency Spend	\$ 378	\$ 3,426	\$ 2,091	\$ 1,055	\$ 494	\$ 528

30 The increased spend in 2022 reflects the costs of clean-up from the Derecho and in 2023, the costs
31 of clean-up from the April ice storm and various summer storms that year. Following those two

1 years, removal of hazardous trees was increased in 2024 as part of Hydro Ottawa’s storm
2 hardening effort. The budget for emergency spending in 2025 and 2026 returns to 2021 levels after
3 factoring in inflationary increases.

4

5 b)

6 i) The phrase “The implementation of the Overstory solution will facilitate precise risk
7 assessment” in reference 1 is a typo and should read “The use of the Overstory solution
8 will facilitate precise risk assessment”. Hydro Ottawa confirms the solution was
9 implemented in 2023 after a pilot test period in 2022 (as indicated in reference 3).

10

11 ii) No productivity benefits are indicated for 2021-2025 because this period is expected to
12 see a temporary increase in work for storm hardening as a result of the information
13 provided by Overstory. This increased work will be targeted to areas at high-risk of
14 impacting the distribution network during storms due to either fall risk from dead/dying
15 trees or fast-growing species encroaching upon the lines between regular cycle
16 trimming.

17

18 iii) Table B shows the annual costs of the Overstory subscription from 2022 (pilot test
19 period) through to the 2026 Test Year.

20

21

Table B - Overstory Annual Subscription Costs (\$'000s)

22

	Historical Years				Bridge Year	Test Year
	2021	2022	2023	2024	2025	2026
Overstory subscription	\$ -	\$ 62	\$ 300	\$ 315	\$ 331	\$ 347

- 1 c)
- 2 i) The procurement process for the Vegetation Management contractor followed Hydro
- 3 Ottawa's procurement policy as set out in Attachment 4-2-2(A) - Procurement Policy.
- 4
- 5 ii) Table C shows the actual and forecasted costs for third-party contractors from 2021
- 6 through 2026.
- 7

8 **Table C - Annual Third-Party Contractor Costs (\$'000s)**

	Historical Years				Bridge Year	Test Year
	2021	2022	2023	2024	2025	2026
Contractor costs	\$ 3,177	\$ 5,278	\$ 5,169	\$ 5,956	\$ 4,741	\$ 5,148

- 12
- 13 d) There are no new positions forecast under the Vegetation Management program for either 2024
- 14 or 2025. There is one new position of Utility Forestry Inspector forecast for 2026. The primary
- 15 job responsibilities of this position are:
- 16
- 17 ● Confirm that contractors work in accordance with applicable laws and safety regulations.
 - 18 ● Inspect contractor performance against quality of work standards.
 - 19 ● Act as a liaison between contractors, overhead line crews, and the Control Room.
 - 20 ● Perform site assessments and create estimates of crew and equipment hours required for each job site.
 - 21 ● Act as a Subject Matter Expert on forestry work.
- 22
- 23
- 24 e) Table D below shows the breakdown of actual and forecast costs for 2021 through 2026 by
- 25 planned trimming, as-needed trimming, and emergency work. The "as-needed" costs include
- 26 spot trimming of fast-growing and hazard trees identified between regular trim cycles, as well as
- 27 proactive, storm-related tree trimming efforts informed by data from Overstory.

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

	Historical Years				Bridge Year	Test Year
	2021	2022	2023	2024	2025	2026
Planned	\$ 2,727	\$ 2,551	\$ 2,902	\$ 3,324	\$ 3,677	\$ 3,910
As-Needed	\$ 706	\$ 743	\$ 1,264	\$ 2,556	\$ 1,650	\$ 1,710
Emergency	\$ 378	\$ 3,426	\$ 2,091	\$ 1,055	\$ 494	\$ 528
Total	\$ 3,811	\$ 6,720	\$ 6,257	\$ 6,936	\$ 5,821	\$ 6,149

The significant increase in vegetation management costs since 2022 is due to a combination of factors, including severe weather, inflationary pressures, and a shift toward more proactive vegetation management.

2022-2023: The primary driver for the increase in 2022 was the Derecho storm, which required a massive, immediate emergency response to clear debris and downed trees. The lingering effects of the storm—such as compromised tree health and an increased number of hazardous trees—continued to drive up costs in 2023. This was further compounded by the April 2023 ice storm. The "as-needed" costs also rose due to a higher number of customer-reported hazards and a focus on proactive tree removals outside regular trim cycles.

2024-2025: In 2024, the increase in costs was primarily driven by inflationary pressures and labor competitiveness, which led to a rise in contractor pricing for the planned trimming program. The "as-needed" program also saw a significant 75% increase in spending compared to 2023, largely due to storm hardening initiatives and the continuation of the right-of-way (ROW) mowing program. The trend of increasing planned trimming costs due to contractor pricing continues into 2025, along with a notable 41% increase in as-needed tree trimming work compared to 2023.

2026 and Beyond: Hydro Ottawa plans to continue leveraging the Overstory technology, a software solution that uses artificial intelligence and satellite imagery to identify hazardous trees. The goal is to shift from a reactive, emergency-based approach to a more proactive one, which is expected to reduce emergency trimming costs in the long term and improve overall system reliability.

1 Another key underlying factor is the City of Ottawa's high tree coverage. As referenced in
2 interrogatory response 1-CCC-5, Table A, Hydro Ottawa has an average urban greenness of
3 87.6%, which is higher than its peer group. This extensive tree canopy is a leading cause of
4 power outages, especially during and after storms when trees are weakened. As a result, Hydro
5 Ottawa requires increased resources to maintain its network and adhere to Distribution System
6 Code standards, a factor that contributes to its higher vegetation management expenses.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-140**

4
5 **EVIDENCE REFERENCE:**

6
7 Station Maintenance OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 25-31 (pdf p. 66-72)

9
10 **QUESTION(S):**

11
12 a) Table 11 in the reference shows a comparison of asset/activity descriptions for the Testing
13 Inspection & Maintenance Activity (Base Program) and the 2026-2030 Program Enhancements.

14 For each of the asset categories, please provide the following:

15 v) Please provide expected cost increases or decreases by implementing the program
16 enhancements in 2026 compared to the base program.

17 vi) Please provide the main drivers of cost increases/decreases associated with each asset
18 category in a) i.

19 vii) Hydro Ottawa states that the program will advance the use of predictive condition based
20 maintenance to enhance efficiency and mitigate unexpected failures as well as leverage
21 the improvements made to data collection and advanced analysis techniques. Did Hydro
22 Ottawa perform any analysis to determine whether there is any future cost saving from
23 efficiency gains/improvements that would be realized to offset the cost increases from
24 the program enhancements? If so, please provide any supporting documents.

25 b) OEB staff notes that although the year-over-year cost increase is less than materiality threshold,
26 the rate of cost increase for the 2024-2026 period is higher than the 2021-2023 period. Please
27 provide the following:

28 i) Please explain in detail any factors that contribute to the higher rate of cost increase for
29 the 2024-2026 period.

30 ii) Please provide the number of new positions hired per year, job titles, and a description
31 of job responsibilities for each job title.

- 1 c) Hydro Ottawa states that it has allocated additional funds for reactive maintenance from
2 2026-2030 to address unanticipated situations. Please provide the following:
- 3 i) How many unanticipated situations occurred between 2021-2024 and what were they?
 - 4 ii) Please provide additional costs incurred per year as a result of unanticipated situations
5 between 2021-2024 in c) i.
 - 6 iii) What is the total annual amount of additional funds allocated to reactive maintenance
7 from 2026-2030 to address unanticipated situations?
 - 8 iv) Please explain how Hydro Ottawa determined the forecast cost for reactive maintenance
9 for the 2026-2030 period.

10

11

12 **RESPONSE(S):**

13

- 14 a) Hydro Ottawa notes that the relevant table in the reference is Table 10.

15

- 16 v) Please see column 2, "Cost Increase/Decrease", of Table A below, that shows the
17 expected cost increases or decreases by implementing the program enhancements in
18 2026 compared to the base program. Station Switchgear and Station Relays have been
19 combined in Table A.

vi) Please see column 3, "Main Driver", of Table A.

Table A - 2026 Program Enhancement Costs

Asset/Systems	Cost Increase/Decrease	Main Driver
Station Inspections (Overall)	\$ 52,850	General inspections and investigations required for 4 kV station decommissioning support
Station Transformers	\$ 342,872	Introduction of new programs inclusive of transformer insulator washing, dissolved gas analysis (DGA) monitor maintenance and advanced diagnostic testing (dielectric frequency response (DFR) testing and online partial discharge (PD) measurement). Support for 4 kV station decommissioning: capital spare determination and relocation
Station Switchgear + Relays	\$ 52,850	Support for 4 kV station decommissioning via capital spare determination and relocation
Station Batteries	\$ 52,850	Support for 4 kV station decommissioning via capital spare determination and relocation
TOTAL	\$ 501,422	

The remaining projected cost increase of \$0.36M for 2026 under station preventative maintenance is related to a general increase in unit labor estimates (based on an increase in the time required to complete comprehensive maintenance relative to the historic procedures) and an increase in the number of station crew performing maintenance, and general inflation, not specific program enhancements.

vii) Please refer to Hydro Ottawa's response to 4-Staff-134 part a) iv), which explains Hydro Ottawa's approach to cost savings from enhancements to the maintenance program as a whole.

b)

i) From 2024 to 2025, Hydro Ottawa experienced an increase in both the estimated unit labor (reflecting actual time and follow-up maintenance) and the number of station crew required for preventative maintenance. Additionally, switching costs increased due to the

1 complexity of load transfer plans, job plan processing, and the switching and restoration
2 tasks performed by field operations and 24/7 crews. For specific factors resulting in the
3 increased spend for 2026, please refer to part a vi) above.

4
5 ii) A breakdown of new positions is provided in the response to interrogatory 4-Staff-159.
6 However, the positions associated with Stations Maintenance are classified under direct
7 labour and, as noted in the response to interrogatory 4-Staff-159, are subject to annual
8 workforce planning review. It should also be noted that increasing stations maintenance
9 does not linearly nor necessarily require additional internal staff. That said, Hydro Ottawa
10 positions that do perform stations maintenance, and their job responsibilities, are as
11 follows:

12
13 **Station Electrician:** Installs, repairs, and maintains electrical and mechanical plant in
14 Hydro Ottawa stations, buildings, structures, and property, including customer-owned
15 transformer vaults. Troubleshoots and repairs electric power distribution apparatus,
16 protection and control devices, electronic equipment, and wiring.

17
18 **Stations Technician:** Participates in the design, development, testing, and integration of
19 various systems within the distribution system. This scope covers Protection and Control
20 for substations, distributed generation, automated field devices, and SCADA. The role
21 also includes power quality analysis and a focus on the Stations Maintenance Program
22 and Record Control.

23
24 c)
25 i) Table A lists major reactive maintenance activities between 2021-2024 associated with
26 specific station asset issues where the spending exceeded \$20,000 (Hydro Ottawa's
27 cost threshold for tracking significant reactive maintenance based on its history of major
28 reactive maintenance projects).

1

Table A - Major Station Reactive Maintenance Activities (2021-2024)

Kanata -Transformer Bushing
Carling TM-SF6 Breakers
Manordale-Transformer and Tap Changer
QCH-Switchgear Bus Issue
Jockvale-Transformer Bushing Issue
Kanata -Transformer Oil Pit
Manordale-Transformer Oil Remediation
Bridlewood-Transformer Oil Leak Repair
Borden Farm-Transformer Oil Leak Repair
Limebank-Transformer Relocation
Munster-Transformer Oil Leak Repair
Blackburn-Hotspot Repairs
ITE Obsolete Breaker Repairs
Russell-Breaker Flashover
Ellwood-P&C Issue
Cambrian-Transformer Bushing
Kanata -Transformer Partial Discharge
Manordale-Tap Changer Interrupture
Merivale-Transformer Cables
Carling-Bus Pothead Cable Failure
Kanata -Transformer Partial Discharge
Barhaven-Switchgear Bus
Cambrian-Transformer Oil Leak Repair
Cassleman-Transformer Bushing
Moulton-Transformer Animal Contact
Transformer Partial Discharge
McCarthy-Station Ground Fault
Rideau Height-SF6 Breakers Issue
Bronson-Transformer Partial Discharge Issue
Bronson-Station Service Issue
Bridlewood-Transformer Internal Discharge

1 ii) Table B shows the actual reactive maintenance costs for the 2021-2024 period, by year.
2 These numbers cover all unanticipated situations, not just those provided in response to
3 part i as well as routine reactive maintenance.
4

5 **Table B - Actual Costs for Reactive Maintenance (\$'000s)**

	Historical Years			
	2021	2022	2023	2024
Reactive Maintenance	\$ 1,077	\$ 1,236	\$ 1,480	\$ 2,266

6
7
8 iii) The reactive maintenance budget for 2026 is \$1.5M. 2027 to 2030 Test Years are
9 forecast using the Custom Revenue OM&A Factor (CROF) as described in Schedule
10 1-3-1 - Rate Setting Framework.

11
12 Hydro Ottawa would like to clarify its statement in Section 3.4.1 of Schedule 4-1-2, “
13 Hydro Ottawa has allocated additional funds for reactive maintenance from
14 2026-2030 to address such unanticipated situations,” this was in comparison to 2021,
15 the reactive maintenance portion for 2026 is \$1.5M which is inline with 2023 actuals.
16 The 2024 reactive maintenance was higher because of additional testing and extensive
17 investigations required with station transformers. Examples include two station
18 transformers at the Bronson substation with partial discharge issues and another station
19 transformer at the Moulton substation with potential issues embedded in the electrical
20 windings due to an animal contact incident.

21
22 iv) The Stations Reactive Maintenance projection is based on an analysis of historical
23 spending. Hydro Ottawa uses an average of recent years spending (as shown in Table
24 B) to establish a baseline removing anomalies. Additionally, an average annual increase
25 has been incorporated to address the rising future costs of equipment and materials.

26
27 Since 2023, as compared to 2021 and 2022, Hydro Ottawa has observed an increased
28 need for reactive maintenance spending, particularly for advanced diagnostic testing,

1 inspections, and refurbishment of station transformers and other major station assets. A
2 notable 2023 example involved localizing the root cause of partial discharge in a major
3 station transformer through testing, preparing for main tank draining, repairing internal
4 damage to a high-voltage bushing connection, and re-energizing the unit after proper
5 moisture removal and oil filtration. Recognizing a continuing need for such repairs and
6 refurbishments, Hydro Ottawa has aligned its 2026-2030 Reactive Maintenance budget
7 with 2023 spending levels, accounting for additional funds required to address similar
8 unforeseen situations.

9
10 Hydro Ottawa collects the required station equipment condition data through its existing
11 inspection program. Unlike distribution assets, station assets can largely be repaired or
12 refurbished when they fail. The increase embedded in this budget aligns with Hydro
13 Ottawa's deliberate shift to condition-driven station asset management and balancing the
14 need for system renewal capital investment with the imperative to manage costs.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-141**

4
5 **EVIDENCE REFERENCE:**

6
7 Distribution Overhead and Underground Maintenance OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 31-33 (pdf pp. 72-74)

9 Ref. 2: Exhibit 1 / Tab 3 Schedule 4 / Table 4 / pp. 23-24 (pdf pp. 543-544)

10
11 **QUESTION(S):**

12
13 a) Table 12 in reference 1 shows the program cost increase of \$0.5M in 2022 and \$5.5M in 2023.
14 Hydro Ottawa states that the cost increase in 2023 was due to reactive maintenance to respond
15 to unexpected severe weather events. Also, several of these extreme weather events occurred
16 during the 84-day labour strike, so contract resources were employed. Please provide the
17 following:

18 i) Given the severe damages of the 2022 Derecho storm, please explain why the cost
19 increase in 2023 was significantly higher than the cost increase in 2022.

20 ii) Please provide the costs of contract resources that were employed by Hydro Ottawa in
21 2023. Please explain how the contracted resources were chosen.

22 b) In reference 1, Hydro Ottawa states that it will expand the use of its Salesforce Field Services
23 platform. Reference 2 shows that Salesforce Field Service will result in \$0.8M productivity
24 benefits for the 2026-2030 period. Please provide the following information:

25 i) When will the expansion of the Salesforce Field Services start in 2026 and is the timing
26 of the expansion still as planned?

27 ii) Table 12 in reference 1 shows that the program cost is forecast to decrease by \$301k in
28 2026 from 2025. Please explain whether this decrease is a result of the productivity
29 benefits of the expansion of the Salesforce Field Service which is embedded to the
30 program cost in 2026?

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RESPONSE(S):

a)

- i) Two primary factors explain why the program cost increase in 2023 was significantly higher than in 2022, despite the severe damages of the 2022 Derecho storm.

1. Nature of Damage: Capital vs. OM&A

The 2022 Derecho storm predominantly caused pole failures, which are classified as capital costs. The total cost of the Derecho was \$23.8M, with \$15.1M allocated to capital expenditures for widespread asset replacement. In contrast, the 2023 storms were more OM&A-intensive, with damage primarily related to downed conductors. The total cost for the 2023 storms was \$9M, of which a substantial \$8.4M was for maintenance work, while only \$0.6M were capital expenditures. This difference in the nature of the damage explains why the 2023 storms resulted in a significantly higher increase in OM&A-related program costs compared to the 2022 Derecho.

2. Labor and Contracted Work

The response to the 2023 storms was significantly affected by the 84-day labour disruption. A high proportion of the repair and restoration work, including standby and response during the storms, was performed by third-party contractors.

- ii) The cost of contracted resources for the Distribution Overhead & Underground Maintenance program was \$5.9M in 2023, as detailed in the response to interrogatory 4-CCC-35, Table A. These resources were selected in accordance with Hydro Ottawa's procurement policy, which is outlined in Attachment 4-2-2(A) - Procurement Policy.

b)

- i) Hydro Ottawa would like to clarify that while the expansion of the Salesforce Field Service for reliability operations is listed as a 2026-2030 Business Priority, a pilot for this expansion actually began in Q4 2024. The full adoption by this group is occurring

- 1 throughout 2025. The overall expansion is currently on track. Starting in Q2 2026, Hydro
2 Ottawa will begin to onboard additional field groups to the Salesforce platform to further
3 leverage its AI capabilities. This will focus on optimizing resource scheduling and
4 dispatch to reduce travel time, increase efficiency, and improve real-time resource
5 assignment.
- 6
- 7 ii) The decrease in program cost from 2025 to 2026 is in part due to productivity savings as
8 a result of expansion of reliability operations as noted in part b i), but also due to a
9 change in budgeting for preventative maintenance. From 2021-2025, Hydro Ottawa
10 allocated a subset of preventative maintenance costs within Distribution Overhead and
11 Underground Maintenance. As Hydro Ottawa's preventive maintenance program will
12 evolve during 2026-2030, these preventative maintenance costs have been transferred
13 to the Testing, Inspection and Maintenance program. This change is reflected in Table 6,
14 Schedule 4-1-2 - Operations, Maintenance, and Administration Program Costs.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-142**

4
5 **EVIDENCE REFERENCE:**

6
7 Metering OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 33-35 (pdf pp. 74-76)

9 Ref. 2: Exhibit 1 / Tab 3 Schedule 4 / Table 4 / pp. 23-24 (pdf pp. 543-544)

10 Ref. 3: Exhibit 1 / Tab 1 / Schedule 2 / p. 6 (pdf p. 47)

11
12 **QUESTION(S):**

13
14 a) Hydro Ottawa states that compensation cost is the main cost driver in this program. Please
15 provide a number of actual and forecast positions and per year from 2021 to 2026. Please also
16 provide job titles and a description of responsibilities for each job title.

17 b) Reference 1 states that a significant initiative during the 2026-2030 period will be the
18 deployment of AMI 2.0 which will contribute to greater operational efficiency. Please provide the
19 following:

20 i) Please describe the operational efficiency gains from AMI 2.0.

21 ii) Is the estimated forecast OM&A cost associated with the AMI 2.0 deployment
22 approximately \$0.7M (reference 3)? If not, please provide the estimated cost.

23 iii) Did Hydro Ottawa perform any analysis to determine whether there is any future cost
24 saving from efficiency gains/improvements that would be realized to offset the cost
25 increase from the deployment of AMI 2.0? If so, please provide any supporting
26 documents.

27 iv) Table 4 in reference 2 shows that the productivity benefits resulting from the Net
28 Metering Automation initiative are forecast at \$6.8M for the 2026-2030 period. Are there
29 any productivity benefits associated with the AMI 2.0 initiative included in the \$6.8M
30 amount?

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RESPONSE(S):

a) Please see Table C in 4-CCC-50 for a table showing FTEs by Appendix 2-JC OM&A Program from 2021-2030, including Metering. Jobs titles included in this program between 2021 and 2026 include:

Meter Technician: Installs, removes, and maintains meters and metering equipment for verification in residential, commercial, substation, and building premises. Calibrates all Hydro Ottawa and utility customer meters. Works on new and existing construction across all Hydro Ottawa service offerings and voltages.

Supervisor, Metering Field Services: Manages the day-to-day operation and scheduling of the business unit. Ensures effective work processes and procedures are developed and implemented, all safety rules, regulations and standards are followed and that all quality assurance provisions and requirements are met.

Manager, Metering Systems: Responsible for smart metering services, including specification, development, implementation, and project management with internal and external partners. Must foster continuous improvement, innovation, and technical/business competency through organizational alignment, support, and accountability.

Field Representative: Handles all field Customer Service activities, including disconnects/reconnects, overdue account collection, and assisting metering with single-phase meter changes.

Meter Data Agent: Responsible for all administrative duties required to administer Hydro Ottawa's residential and commercial metering and equipment including the set-up of customer accounts and the creation of electronic field activities for the Metering Group.

Meter Shop Attendant: Responsible for Metering Materials issuance and Meter Inspection duties of processing incoming / outgoing Meters.

b)
i) Operational efficiencies from the proposed AMI 2.0 deployment are: enabling enhanced remote meter management, grid feedback and data collection; reduced meter

1 communication errors and additional needs for operational activities; minimize billing
 2 errors and customers disputes, leading to cost savings; enhanced data analytics for
 3 quicker outage response; and data integration with other programs (please refer to
 4 Section 5.4.1 of Schedule 2-5-7 - System Renewal Investments for further details).

5
 6 ii) Hydro Ottawa assumes Reference 3 refers to Schedule 4-1-2 - Operations, Maintenance
 7 and Administration Program Costs. Hydro Ottawa confirms that the 2026 estimated
 8 forecast OM&A cost associated with the AMI 2.0 deployment is approximately \$0.7M,
 9 though the estimated OM&A cost for 2026-2030 is \$6.5M, as per Table 21, page 138 of
 10 Schedule 2-5-7 - System Renewal Investments.

11
 12 It is important to note, however, that the AMI 2.0 project is planned as a phased, 10-year
 13 deployment (see Section 5.7 of Schedule 2-5-7 - System Renewal Investments for more
 14 details on the implementation plan).

15
 16 iii) Hydro Ottawa performed an analysis of potential future cost savings when developing
 17 the deployment alternatives for the AMI 2.0 program, as outlined in Section 5.6.1 of
 18 Schedule 2-5-7 - System Renewal Investments. To prioritize customer affordability and
 19 prevent future cyclical investment patterns, Hydro Ottawa selected Alternative 2, which
 20 plans a 10-year deployment. Table A shows the estimated OM&A cost savings for each
 21 year of the forecast period, totalling \$3.2M by the end of 2030. The supporting
 22 calculations are in Attachment 4-Staff-142(A) - AMI Potential Future Cost Savings.

23
 24 **Table A - AMI Potential Future Cost Savings, 2026-2030 (\$'000s)**

	Forecast Years				
	2026	2027	2028	2029	2030
OM&A Savings	-	\$ 251	\$ 463	\$ 1,005	\$ 1,443

25
 26
 27
 28
 29 iv) The \$6.8M in productivity benefits described in Reference 2 does include some savings
 30 from the AMI 2.0 initiative, which are described in Section 3.2.3 - Remote Disconnection
 31 Technology.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-143**

4
5 **EVIDENCE REFERENCE:**

6
7 System Operations & 24/7 Maintenance OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 35-37 (pdf pp. 76-78)

9
10 **QUESTION(S):**

11
12 a) Hydro Ottawa states its priorities and goals for this program (e.g. enhancing real time monitoring
13 and control, streamlining outages response, ongoing technology upgrades and process
14 optimization, etc.) over the rate term in section 3.7.1. Please explain in further detail what
15 initiatives will be taken by Hydro Ottawa to meet these priorities and goals over the 2026-2030
16 period.

17 b) Please provide a summary of reactive maintenance activities that resulted in the \$4.6M cost
18 increase in 2022 from 2021.

19 c) Please explain in further detail the increased cost of \$1.1M in 2023 associated with the strike
20 (e.g. breakdown of the costs, drivers of the increase, etc.).

21 d) Are there any new positions forecast for 2026? If so, please provide a number of positions, job
22 titles and job responsibilities.

23
24 **RESPONSE(S):**

25
26 a) To meet the goals and priorities described in Section 3.7.1 of Schedule 4-1-2 - Operations,
27 Maintenance and Administration Program Costs, within the System Operations & 24/7
28 Maintenance OM&A Program, Hydro Ottawa plans to undertake the following key initiatives:

- 29 • Continuous Process Review for Day-to-Day Operations: The organization will continuously
30 review existing processes for day-to-day operations to ensure they maintain best-in-class
31 reliability and deliver excellent customer service. A specific focus will be placed on

- 1 enhanced training for control room operators to leverage increased system observability and
2 automation, specifically related to increased deployment of smart FCIs and automated
3 switches with an outcome of streamlining outage response and restoration efforts.
- 4 ● Iterative Review and Training for Electrical Emergency Response Program (EERP): Hydro
5 Ottawa is committed to the continuous, iterative review of its Electrical Emergency
6 Response Program (EERP). This includes regular, planned training sessions for all
7 participants to ensure preparedness and coordination during emergency situations. An
8 improved Outage Management System (OMS) and enhanced grid visibility through ADMS
9 and FAN will further support better real-time outage restoration and overall grid
10 management.
 - 11 ● Regular Safety Metric Review: Hydro Ottawa will regularly review safety metrics and
12 challenge the status quo to ensure that all aspects of system planning and switching
13 prioritize safe, reliable, and customer-centric operations. This commitment is part of a
14 broader shift towards a data-driven maintenance strategy, utilizing advanced inspection
15 technologies like drone inspections to gather precise data and optimize investments for
16 reliability and long-term sustainability.
 - 17 ● System Visibility: Hydro Ottawa also plans to deploy next-generation smart meters (AMI 2.0)
18 and grid sensors, leveraging their data capabilities to maximize visibility and control over
19 grid assets.
 - 20 ● Active Participation in ADMS Initiative: Hydro Ottawa will actively participate in, rigorously
21 test, and seamlessly integrate support for its Advanced Distribution Management System
22 (ADMS) initiative. This involvement is crucial as the ADMS forms a cornerstone of grid
23 modernization, enhancing stability, efficiency, resilience, and real-time outage restoration
24 capabilities. The Field Area Network (FAN) program will provide the necessary
25 communication backbone for ADMS and other grid devices, ensuring real-time data access
26 and strengthening cybersecurity.
- 27
- 28 b) Table A provides a summary of reactive maintenance activities that resulted in the \$4.6M cost
29 increase in 2022 from 2021. They are largely driven by the Derecho storm. Further details on
30 the impacts of the Derecho storm are provided in Attachment 2-1-1(A) - Derecho May 2022
31 After Storm Report.

1 **Table A - 2022 Reactive Maintenance within System Operations & 24/7 Maintenance Program**

	Historical Year
	2022
Internal labour	\$ 3,194
Contracted Services	\$ 971
Other	\$ 414
TOTAL	\$ 4,579

2

3

4 c) Hydro Ottawa wishes to clarify that the explanation provided in reference 1 is incorrect. The
5 original explanation was “Costs from 2022 to 2023 decreased by \$1.3M as a result of \$2.4M
6 less spent on reactive maintenance for in-year storm damage, with an offset of \$1.1M increased
7 costs associated with the 2023 strike”. The corrected explanation is “ The costs from 2022 to
8 2023 decreased by \$1.3M, primarily driven by a reduction in reactive maintenance
9 expenditures”. The overall costs associated with the strike are included in the response to
10 Interrogatory 4-SEC-70.

11

12 d) There are 3 new positions forecasted for 2026, please see the response to interrogatory
13 4-Staff-159. The job title and responsibilities are described below. Additionally, the annual
14 Workforce Planning exercise discussed in the response to interrogatory 4-Staff-159 includes a
15 review of System Operations positions and, based on expected work volumes, direct labour
16 positions within System Operations may be added.

17

- 18 ● System Operations Planner (2): The System Operations Planner holds key responsibilities
19 for the distribution system. This includes assessing and approving all work requests
20 submitted to the Controlling Authority that involve the distribution system. Furthermore, the
21 System Operations Planner is tasked with organizing, prioritizing, and planning these
22 requests, as well as scheduling all associated work activities for the System Control Centre.
- 23 ● Vault Maintenance Technical Specialist (1): The Vault Maintenance Technical Specialist is
24 responsible for the inspection, regular maintenance and shutdown coordination of customer
25 owned / Hydro Ottawa owned vaults, switchgear and customer owned substations. It also

- 1 supports a wide range of field services for residential, large commercial and industrial
- 2 customers and provides technical services internally.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-144**

4
5 **EVIDENCE REFERENCE:**

6
7 Engineering & Design OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / Section 3.8.2 / p. 39 (pdf pp. 80-81)

9
10 **QUESTION(S):**

11
12 a) In 2024, Hydro Ottawa states that the Engineering & Design OM&A program cost is forecast to
13 increase by \$1.5M due to the addition of 17 new positions related to the growing number of load
14 requests and planned investments in grid modernization and electrification activities. Please
15 provide the following:

16 i) Explain how Hydro Ottawa determined the number of positions required and provide any
17 underlying calculations to support how the 17 new positions were determined.

18 ii) Please provide job titles and the number of new positions associated with each title.

19 b) In 2026, the forecast total cost increase of \$6.3M in Engineering & Design OM&A program is
20 partly due to the \$2.2M increase in compensation which includes 22 incremental positions to
21 support system expansion, project volumes and grid resilience. Please provide the following:

22 i) Explain how Hydro Ottawa determined the number of positions required and provide any
23 underlying calculations to support how the 22 new positions were determined.

24 ii) Please provide job titles and the number of new positions associated with each title.

25 iii) Has Hydro Ottawa considered phasing the hiring of these positions over the 5-year
26 period?

1

2 **RESPONSE(S):**

3

4 a)

5 i) Hydro Ottawa followed the principles outlined in Section 3 of Attachment 4-1-3(B) -
6 Workforce Planning Strategy to determine the 17 positions shown within Engineering &
7 Design per Table 1 of Section 3, Schedule 4-1-3 - Workforce Staffing and Compensation.
8 In 2024, the main drivers for increased work volumes were:

- 9
- 10 ● Customer Connection and Capacity Program Growth,
 - 11 ● DER and Capacity Connection Request Complexity,
 - 12 ● Grid Modernization, and
 - 13 ● Enhanced Leadershipship and Oversight

13

14 Based on the proposed volume of work associated with the above drivers (also
15 illustrated in Section 3.1.1 of Attachment 4-1-3(C) - Workforce Growth for reference),
16 position volumes were determined by comparing historical needs to that of work
17 programs within the 2024 drivers. Positions were then attributed to the categories shown
18 in response to interrogatory 4-Staff-159.

19

20 ii) Please see response to interrogatory 4-Staff-159.

21

22 b)

23 i) Hydro Ottawa followed the principles outlined in Section 3 of Schedule 4-1-3(B) -
24 Workforce Planning Strategy to determine the 22 positions shown within Engineering &
25 Design of Table 1 of Section 3, Schedule 4-1-3 - Workforce Staffing and Compensation.
26 In 2026-2030, the main drivers for increased work volumes are equivalent to the four
27 main investment priorities, plus others:

- 28
- 29 ● Growth and Electrification
 - 30 ● Renewing Deteriorating Infrastructure
 - 31 ● Grid Modernization
 - Enhancing Grid Resilience

- 1 ● Growth in Operations, Maintenance and Administration, and
2 ● Enhanced needs in System Office, Engineering, Contactor Management, Project
3 Execution and Leadership.

4
5 Based on the proposed volume of work associated with the above drivers (also
6 illustrated in Section 3.1.2 of Attachment 4-1-3(C) - Workforce Growth), position volumes
7 were determined by comparing historical needs to that of the work programs and needs
8 for 2026-2030. Positions were then attributed to the categories shown in response to
9 interrogatory 4-Staff-159.

- 10
11 ii) Please see response to interrogatory 4-Staff-159.
- 12
13 iii) Yes, Hydro Ottawa's plans have pre-emptively included phasing of the required positions
14 over the 5-year period as shown in Table 4, Section 3, Attachment 4-1-3(C) - Workforce
15 Growth.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-145**

4
5 **EVIDENCE REFERENCE:**

6
7 Distribution Support OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 40-42 (pdf pp. 81-83)

9 Ref. 2: Exhibit 1 / Tab 3 Schedule 4 / Table 4 / pp. 23-24 (pdf pp. 543-544)

10
11 **QUESTION(S):**

12
13 a) In reference 1, Hydro Ottawa states that costs in the Distribution Support Program are driven by
14 salaries and benefits, net of allocations to capital, Maintenance, and Services to Third Parties
15 work, non-capital tools, safety gear, and office expenses. Please provide actual/forecast cost for
16 each of these drivers for 2021 to 2026.

17 b) Please explain the third party services that Hydro Ottawa has used and will use for the 2021 to
18 2026 period.

19 c) Reference 1 states that the goals for this program are continuous improvement in processes,
20 leveraging technology to enhance accuracy and efficiency, and aligning with regulatory and
21 industry standards. In addition, the introduction of the Salesforce CRM platform to the Service
22 Desk team has created efficiency gains. Table 4 in reference 2 shows the productivity benefits
23 from the CRM initiative for the 2021 to 2030 period are for capital expense, capital depreciation
24 and services to third parties. Are there any cost savings realized as part of the OM&A costs
25 from 2021 to 2030?

26 i) If so in response to c), please provide the OM&A cost saving for 2026. Please comment
27 whether the cost savings have been embedded in the program cost in Table 16 of
28 reference 1.

29 ii) If not, please explain why there are no cost savings resulting from the efficiency gains
30 stated in reference 1.

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RESPONSE(S):

a) Please see Table A for the actual/forecast costs of 2021 to 2026 by cost driver. Note that the “Other” line item reflects cost recoveries for labour and fleet.

Table A - Distribution Support Costs by Driver, 2021-2026 (\$'000s)

Cost Driver	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Compensation	\$ 32,612	\$ 35,010	\$ 30,693	\$ 37,621	\$ 40,220	\$ 46,312
Fleet	\$ 3,293	\$ 4,040	\$ 3,496	\$ 4,294	\$ 4,367	\$ 4,255
Non-capital tools	\$ 512	\$ 600	\$ 595	\$ 663	\$ 663	\$ 797
Safety gear	\$ 311	\$ 288	\$ 289	\$ 389	\$ 389	\$ 438
Other	\$ 205	\$ 485	\$ 652	\$ 651	\$ 698	\$ 1,114
Allocation	\$ (35,754)	\$ (37,390)	\$ (31,292)	\$ (36,664)	\$ (40,995)	\$ (47,473)
TOTAL	\$ 1,179	\$ 3,032	\$ 4,433	\$ 6,954	\$ 5,342	\$ 5,443

b) Hydro Ottawa Fleet uses third-party contractors for specialized services and overflow work. Aerial boom inspections and dielectric certifications are conducted semi-annually and annually by factory-trained technicians on-site, with any defects repaired by internal fleet staff. External contractors are also engaged for heavy-duty tire work, major transmission repairs, specialized welding, vehicle pressure washing, and to handle workload surges to reduce downtime.

c) There are no quantifiable OM&A cost savings as a result of the efficiency gains through use of the Salesforce CRM platform. The teams leveraging the CRM platform are primarily engaged in capital and Services to Third Parties work as shown in Table 4 of Section 3.2 of Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement, therefore the cost savings are seen in those programs and the impact to OM&A is minimal.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-146**

4
5 **EVIDENCE REFERENCE:**

6
7 Distribution Support OM&A Program
8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 42-43 (pdf pp. 83-84)

9
10 **QUESTION(S):**

- 11
12 a) Although Table 17 in reference 1 shows no material cost increases for the 2021-2026 period,
13 OEB staff notes that the rate of increase has changed from a relatively flat growth from
14 2021-2023 to a much higher growth rate from 2024 to 2026. Please provide the following:
- 15 i) Please provide a reason for the sharp increase between the 2024-2026 period.
 - 16 ii) Is the increasing trend expected to continue into the forecast period to 2030? Please
17 explain.

18
19
20 **RESPONSE(S):**

- 21
22 a) Hydro Ottawa notes that the program in reference 1 is Minor Maintenance and has answered
23 the question on this basis.
- 24 i) The costs for the 2024 and 2025 Bridge years were underestimated. These costs are
25 primarily internal labour allocated among different programs within the OM&A budget.
26 While this re-allocation affects individual program budgets, it has no overall impact on
27 the total OM&A budget. The actual spending for the Minor Maintenance program in 2024
28 was \$1.5M. This represents a steady increase from the 2021-2023 average of \$1.3M
29 and is below the \$1.7M projected for the 2026 test year.
 - 30 ii) No, the increasing trend is not expected to continue, the budget for the Minor
31 Maintenance program has relatively modest growth from 2026-2030.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-147**

4
5 **EVIDENCE REFERENCE:**

6
7 Collections OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 43-45 (pdf pp. 84-86)

9 Ref. 2: Exhibit 1 / Tab 3 / Schedule 4 / Sections 3.2.3 and 3.2.5 / pp. 26 and 28 (pdf Exhibit 1 part 1,
10 pp. 546, 548)

11
12 **QUESTION(S):**

- 13
14 a) Please describe how bad debt expenses are calculated for the forecast years.
15 b) Please explain the increasing trend in the Collections OM&A program cost, given that Hydro
16 Ottawa is implementing the initiatives found in references 1 and 2 to address collections issues
17 and improve efficiency.
18

19
20 **RESPONSE(S):**

- 21
22 a) Hydro Ottawa uses an expected credit loss (ECL) methodology to calculate bad debt expense
23 for its electricity and other trade receivables, in accordance with IFRS. This process involves an
24 assessment of each account balance based on factors such as aging, whether the account is
25 active or finalized, and if it is part of a special payment plan (e.g., Equal Monthly Payment Plan
26 or Arrears Payment Agreement). These factors are used to categorize the accounts, and an
27 appropriate ECL rate is then applied to each group. This rate is determined using historical data
28 and forward-looking information, such as economic factors and government policy. The forecast
29 also integrates growth of electricity revenue, as higher revenues are expected to lead to a
30 proportionately higher bad debt expense.
31

1 b) As can be seen in Table A in the response to interrogatory 4-CCC-44, the increasing trend in the
2 Collections OM&A program cost is primarily due to the increase in bad debt expenses which
3 account for 73% of the costs in this program in the 2026 Test Year. Bad debt expenses and
4 write-offs due to uncollectable accounts rose significantly following the conclusion of
5 government assistance programs related to the COVID-19 pandemic, further heightened by the
6 impact of external economic factors such as higher inflation and increased interest rates. The
7 other costs in this program are labour costs and external collection/credit checks, which have
8 remained relatively flat between 2021 and 2026. This is largely due to the fact that Hydro
9 Ottawa has implemented new strategies to improve efficiency since 2019 and 2020, such as
10 Remote Disconnection Technology and Disconnection Notification Automation (as per
11 References 1 and 2). The productivity benefit has been the reduction and avoidance in staff
12 costs as a result of reducing the amount of field work required for disconnections/reconnections
13 and hand-delivered notices. These savings started in 2019/2020 and have persisted through
14 2021-2025 and will continue through 2026-2030. It has allowed Hydro Ottawa to maintain the
15 staffing levels in the Collections OM&A program flat despite increases in the number of
16 disconnections each year.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-148**

4
5 **EVIDENCE REFERENCE:**

6
7 Customer Billing OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 45-46 (pdf pp. 86-87)

9 Ref. 2: Exhibit 1 / Tab 3 / Schedule 4 / p. 25 (pdf Exhibit 1 part 1 p. 545)

10
11 **QUESTION(S):**

12
13 a) Please describe how the Meter-to-Cash program (reference 1) has improved customer
14 experience and billing accuracy, and provide the savings achieved as well as projected savings
15 from this program.

16 b) In reference 1, the forecasted expense for 2024 is expected to increase by \$1.3M compared to
17 2023. This is primarily driven by higher IT costs related to Meter-to Cash (\$0.6M),
18 finance-related costs to support customer billing (\$0.4M), and compensation adjustments
19 (\$0.3M).

20 i) Please explain factors that contributed to the Meter-to-Cash IT cost increase of \$0.6M in
21 2024. Is this a one-time increase or recurring expense?

22 ii) Please explain the finance related costs that contributed to the \$0.4M increase in 2024.

23 c) Hydro Ottawa stated in reference 2 (lines 14-16) that online billing enrollment was projected to
24 be maintained at 80% through 2030.

25 i) Does Hydro Ottawa have any planned initiatives to increase the enrollment above 80%?
26 If so, please explain.

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RESPONSE(S):

a) The Meter-to-Cash Program is integral to Hydro Ottawa's core operations, encompassing all facets and technological components from meter installation and Advanced Metering Infrastructure (AMI) to billing and collections. This program forms the fundamental structure for customer service, both billing accuracy and customer experience.

Specifically, improvements have been realized through:

- **Billing Accuracy:** The implementation and ongoing maintenance of Advanced Metering Infrastructure (AMI) provides more precise and timely consumption data, significantly reducing estimated bills and improving overall billing accuracy. Net Metering Automation has further streamlined the complex billing processes for net metering customers, minimizing errors as the process is no longer manual. This is reinforced by Hydro Ottawa's billing accuracy rate of 99.9% between 2019 and 2023, per Section 2.2.2 of Attachment 1-3-3 (C) - Electricity Utility Scorecard Benchmarking Analysis.
- **Customer Experience:** Online Billing Enhancements offer customers greater convenience, access to information, and control over their accounts, while Move-In Move-Out Automation has streamlined account transfers, reducing administrative burden and potential errors during customer move processes. These improvements contribute to a smoother, more transparent, and more reliable billing interaction for customers.

For a detailed breakdown of savings achieved and projected from the Meter-to-Cash program, please reference Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement, page 23, Table 4. This table encompasses savings and cost avoidance from this and other related initiatives such as Customer Information System Reduced Fees that were part of the Meter-to-Cash program.

b)

i) The increase of \$0.6M to IT costs for 2024 is due to annual increase in IT maintenance contracts for the CC&B, Honeywell, EBT Hub and other systems integral to the

- 1 Customer Billing function, as well reclassification of the Savage Data Systems metering
2 software from Customer & Community Relations to Customer Billing in 2024. These are
3 all recurring expenses.
4
- 5 ii) The finance-related costs that contributed to the \$0.4M increase in 2024 represent an
6 allocation of employees' time supporting activities that are classified as Customer Billing
7 activities.
8
- 9 c) Hydro Ottawa does not have any planned initiatives to increase the enrollment above 80%. As
10 noted in Schedule 1-3-1 - Rate Setting Framework, Hydro Ottawa has already embedded
11 productivity into the 2026 OM&A Test Year forecast for this ambitious stretch target of 80% for
12 online billing adoption by the end of 2025, and built the associated savings into its 2026 base
13 OM&A as a direct benefit to customers. As a result, the utility assumes a significant financial risk
14 of managing the incremental printing, postage and other related costs should this ambitious
15 target not be met or sustained over the rate term.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-149**

4
5 **EVIDENCE REFERENCE:**

6
7 Customer & Community Relations OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 46-48 (pdf pp. 87-89)

9 Ref. 2: Exhibit 2 / Tab 5 / Schedule 9 / p. 1 / (pdf Exhibit 2 part 4, p. 579)

10 Ref. 3: Exhibit 1 / Tab 3 / Schedule 4 / Table 4 and Section 3.2.8 / pp. 23, 30 (pdf Exhibit 1 part 1 pp.
11 543, 550)

12
13 **QUESTION(S):**

14
15 a) The projected expense for this program in 2024 is \$1.3M higher than 2023, mainly due to an
16 increase in compensation related to the strike (\$1.1M) and higher external customer contact
17 center cost (\$0.2M).

18 i) Please explain in further detail the \$1.1M increase in compensation costs in 2024 in
19 relation to the strike. How many positions were involved? What were the expenses
20 incurred?

21 ii) Please explain in further detail the increased contract rates and volumes of calls which
22 contributed to the \$0.2M increase in the external customer contact center costs in 2024.

23 b) For 2026, Hydro Ottawa projects an increase of \$1.4M compared to 2025 due to cloud
24 computing and subscription costs related to Customer Relationship Management, My Account
25 enhancements, and one additional IT position (reference 1).

26 i) In reference 2, the OM&A cost for customer engagement platform amounts to \$4.3M for
27 the 2026 to 2030 period. This includes MyAccount as one of the initiatives under this
28 program. Please provide the specific cost related to MyAccount enhancements for 2026
29 and provide both the quantitative and qualitative benefits of these enhancements.
30 Please explain whether this is expected to be completed by 2026 or phased through
31 2030.

- 1 ii) Please provide a table which shows the total cloud computing implementation
2 subscription cost per year from 2021 to 2026.
- 3 iii) Please confirm if the additional IT position in 2026 will be dedicated solely to this
4 program. If not, what are the other responsibilities for this position?
- 5 c) Reference 1 refers to the impact of the Move-In Move-Out Automation initiative as part of Hydro
6 Ottawa's Facilitating Innovation and Continuous Improvement. Table 4 in Reference 3 shows
7 that the productivity benefit from the Move-In Move-Out Automation initiative is forecast to be
8 \$0.9M for the 2026-2030 period. Please explain whether the forecast productivity saving from
9 the Move-In Move-Out Automation initiative has been incorporated into the Customer and
10 Community Relations OM&A Program cost in 2026, given that the forecast cost increase in this
11 program is above the materiality threshold (\$1.4M for the year).
- 12
13

14 **RESPONSE(S):**

15

- 16 a)
- 17 i) The \$1.1M increase in compensation costs in 2024 is primarily due to the impact of the strike
18 in 2023, during which unionized employees were not paid, resulting in lower actuals for that
19 year. The 2024 figures reflect a return to normal operating levels for union compensation,
20 which included the post-labour negotiation wage increases. The strike affected all unionized
21 positions within Customer & Community Relations. The number of full-time equivalent (FTE)
22 positions in this program decreased from 44 in 2022 to 32 in 2023, as stated in the
23 interrogatory response 4-CCC-50.
- 24
- 25 ii) The \$0.2M increase in external customer contact center costs in 2024 is primarily driven by
26 higher call volumes. In 2024, there were 220,000 inbound/outbound calls and 13,000
27 outage-related calls, compared to 198,000 and 15,600 respectively in 2023. The increase in
28 total call volumes, combined with 10% higher contracted rates, contributed to the overall
29 cost increase.

- 1 b)
- 2 i) The MyAccount OM&A portion of the \$4.3M in Customer Engagement Platforms is limited to
- 3 150K per year for 3rd party support of the Customer Portal “MyAccount”. This annual fee
- 4 ensures Hydro Ottawa has basic support of the platform, monitoring and issue resolution,
- 5 periodic upgrades of technology components and minor enhancements to support regulatory
- 6 obligations and incremental improvements to the customer experience. MyAccount enables
- 7 and supports customer-facing enhancements, self-service and system integrations, which
- 8 leads to indirect savings through reduced human intervention and improved customer
- 9 experience. These benefits are not readily quantifiable, as MyAccount’s contributions are
- 10 embedded within broader initiatives rather than tracked separately.
- 11
- 12 ii) Table A shows the annual costs for 2021-2026 for cloud computing implementation and
- 13 subscription costs.
- 14

Table A - Cloud Implementation Costs for Customer & Community Relations, 2021-2026
 (\$'000s)

	Historical Years			Bridge Years		Test Years
	2021	2022	2023	2024	2025	2026
Cloud Computing Costs	\$ 895	\$ 517	\$ 919	\$ 670	\$ 611	\$ 2,403

- 15
- 16
- 17 iii) Confirmed. As noted in Reference 1, the additional IT position added in 2026 will focus on
- 18 developing and supporting customer-centric solutions, including online self-service portals,
- 19 mobile applications, personalized communication channels, and AI-driven enhancements to
- 20 customer service and engagement.
- 21
- 22 c) Yes, the forecast productivity savings and cost avoidance from the Move-In Move-Out
- 23 Automation initiative have been incorporated into the 2026 Customer and Community Relations
- 24 OM&A Program cost. As noted in Schedule 4-1-2 – Operations, Maintenance and
- 25 Administration Program Costs, the impact of this initiative is referenced in Schedule 1-3-4 –
- 26 Facilitating Innovation and Continuous Improvement. The productivity benefit is the net

1 reduction and avoidance in Contact Centre costs, which are the result of automation-driven time
2 reductions minus the depreciation of the billing system enhancement. These savings started in
3 2022 and have persisted through 2023-2025 and will continue through 2026-2030. Thus, the
4 2026 budget reflects the ongoing benefits of the initiative.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-150**

4
5 **EVIDENCE REFERENCE:**

6
7 Information Management and Technology OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2/ pp. 48-53 (pdf pp. 89-94)

9 Ref. 2: Exhibit 4 / Tab 1 / Schedule 2 / pp. 47-48 (pdf pp. 88-89)

10
11 **QUESTION(S):**

12
13 a) Hydro Ottawa's Customer & Community Relations program includes initiatives aimed at
14 improving customer experience such as maintaining IT-based customer platforms. The cost for
15 these initiatives were included in the forecasted expense (reference 2, page 89, lines 13-16).
16 Within the Information Management and Technology OM&A program, Hydro Ottawa also
17 mentioned enhancing customer experience as a key area of focus.

18 i) Please clarify the distinction between the two programs, Information Management and
19 Technology and Customer and Community Relations, in terms of costs allocated for
20 customer experience enhancement.

21 ii) Please confirm that the initiatives related to similar customer experience objectives were
22 not accounted for more than once.

23 b) Please provide the savings realized from the implementation of Esker and Google Workspace in
24 2022, as described in reference 1.

25 c) For the cost increase of \$1.8M in 2024 from 2023 shown in reference 1, please provide a
26 breakdown of the increase into consulting costs, technology costs, and salaries. Please also
27 explain whether consultant costs and technology costs are one-time expenses or recurring
28 expenses.

29 d) As stated in reference 1, the program expense in 2025 is projected to increase by \$1.4M
30 primarily due to increases in compensation (\$0.7M), additional costs for consultancy, IT
31 contracts and subscriptions (\$0.5M), and rental for a new backup data center (\$0.2M).

- 1 i) Please explain the additional consulting costs which contributed to the \$0.5M increase.
2 Is this a one-time expense or recurring expense?
- 3 ii) Please confirm whether the location of the backup data centre aligns with the
4 recommendation from the Derecho storm action report.
- 5 iii) Has Hydro Ottawa considered other alternative locations for the backup data center. If
6 yes, was a cost comparison considered? If not, please explain why.
- 7 e) Based on reference 1, the forecasted expense in 2026 is projected to increase by \$1.7M
8 primarily due to annual inflationary increases in compensation and five new positions (\$1M),
9 inflationary increases to software subscription fees (\$0.4M), and the implementation of AI-driven
10 solutions (\$0.3M).
- 11 i) Please explain the five new positions being filled under this program, including their
12 respective key roles and responsibilities. Are these positions dedicated solely to Cloud
13 Computing, Cyber Security and Data & Systems Integration and Program Management?
- 14 ii) Please clarify whether Hydro Ottawa has considered phasing the hiring of these
15 positions over the 5-year period, and what consideration was made to support the
16 decision to hire all five positions in 2026.
- 17 iii) Did Hydro Ottawa explore other alternatives such as contracting or outsourcing these
18 five positions? Please explain.
- 19 iv) Please explain the specific AI-driven solutions being considered in the forecast. Are
20 these one-time costs or subscription-based?
- 21 v) Please explain the urgency of these AI-solutions and outline the implementation plan.
22 Will all these initiatives be implemented in 2026?
- 23 vi) Given the significant expenses related to software, cloud-based computing, and
24 subscription costs, has Hydro Ottawa pursued negotiations with other vendors to get
25 more favourable rates?
- 26 vii) Please provide the basis for the increase in software subscription fees.
- 27 f) Please provide a table detailing Hydro Ottawa's major subscription costs from 2021-2026.
- 28 g) Are there any estimated cost savings from these above initiatives that have been incorporated
29 in the 2026 forecast? Is so, please explain where they have been incorporated into the
30 application.

1 _____
2 **RESPONSE(S):**

3
4 a)

5 i) Technology costs that directly benefit customers, such as the Customer Engagement
6 Platform, Customer Relationship Management System, and MyAccount, are included in
7 the Customer & Community Relations budget. Conversely, non-customer-centric
8 technologies like cybersecurity are reported under the Information & Technology
9 program. However, corporate IT staff who support customer-centric projects are also
10 part of the Information & Technology program.

11
12 ii) Confirmed.

13
14 b) The savings realized from implementation Esker and Google Workspace are not easily
15 quantifiable. Both software solutions have improved employee productivity (as described in the
16 reference) and have prevented Hydro Ottawa from incurring more labour costs. However the
17 time increments saved per task are not practical to track and are therefore difficult to accurately
18 quantify.

19
20 c) Table A provides a breakdown of the cost increase from 2023 to 2024 by the requested
21 categories.

22 **Table A - Increase in IT costs**

Cost Category	Var (\$'000s)
	2023 - 2024
Consulting	\$ 414
Technology	\$ 481
Salaries	\$ 443
Other	\$ 456
TOTAL	\$ 1,794

1 Consultant costs are partly recurring, for the annual upgrades and enhancements of
2 applications, and partly one-time, for the implementation of new applications. Technology costs
3 are driven by software subscriptions and are expected to recur annually.
4

5 d)

6 i) The additional consulting costs that contribute to the \$0.5M increase in 2025 are a
7 combination of one-time costs for implementation of new applications and recurring
8 costs for enhancement of existing ones.

9 ii) Confirmed.

10 iii) A thorough analysis was conducted to determine the appropriate location to host the
11 secondary data centre. This analysis took into account location, capabilities,
12 environmental factors, accessibility and cost.
13

14 e)

15 i) The five new positions fall into three groups:
16

17 1) Cybersecurity & IT Infrastructure

18 (a) Cloud Engineer will be responsible for managing, operating and
19 supporting our cloud infrastructure footprint, including Amazon Web
20 Services (AWS) and Google Cloud Platform (GCP) tenants.

21 (b) Cyber Security Engineer will be responsible for working within the entire
22 cyber security team in the protection of the organization by employing a
23 range of technologies and processes to prevent, detect and manage
24 cyber threats across data and infrastructure platforms including both
25 information technology (IT) and operational technology (OT)
26 environments. This entails ensuring that Hydro Ottawa's detective,
27 preventative and administrative controls are in place, functioning correctly
28 and able to identify gaps and anomalies that could lead to possible
29 incidents.

30 (c) Supervisor, OT Cyber Security will be responsible for supervision,
31 development, planning, implementation and protection of the

1 organization's cybersecurity posture by employing a range of
2 technologies and processes to prevent, detect and manage cyber threats
3 across data and infrastructure platforms in the operational technology
4 (OT) environments. They will design, implement, coordinate and measure
5 the monitoring and administration of OT internal security services,
6 controls and programs to ensure that a high level of cyber security is
7 maintained for Hydro Ottawa.
8

9 2) Planning and Programs

10 (a) Manager, Systems Programs is responsible for managing a cross section
11 of information technology projects and for stakeholder engagement
12 through the project lifecycle. The Manager, Systems Programs works
13 closely with the Manager, IT Planning and Program Management as well
14 as stakeholders at all levels across the organization to understand
15 requirements and translate them into project plans to develop new or
16 support existing IT programs. The expansion of our Information
17 Technology projects to include Operations Technology projects
18 necessitates an increase in our current headcount.
19

20 3) Grid Technology

21 (a) Systems Engineer will be responsible for developing the solution design
22 for operations technologies including telecommunications, ADMS, and
23 other Grid Technology systems. This role is responsible for ensuring
24 solutions integrate in a robust and reliable way by working with cyber
25 security, data management and other subject matter experts. Due to the
26 volume and complexity of new technology and integrations required for
27 Grid Modernization, this position is essential.

- 28 ii) The main driver for hiring these positions in 2026 is to support the Grid Modernization
29 Program.
30 iii) Hydro Ottawa explored outsourcing alternatives for these five positions, however hiring
31 additional employees for the roles is a more cost-effective option.

- 1 iv) Hydro Ottawa will explore AI solutions such as agent assistants, chatbots and AI-driven
2 tools within cloud based contact center, customer self serve and automation
3 opportunities in the 2026 period and has forecast \$200k. The solutions will be a mix of
4 one-time costs (implementation services) and subscriptions (ongoing computing costs).
5 v) Hydro Ottawa will explore and implement AI solutions in the 2026-2030 timeframe. Like
6 many businesses, Hydro Ottawa is looking to AI for a wide range of strategic and
7 operational benefits. The adoption of AI is driven by its potential to address key business
8 challenges and unlock new opportunities for growth, operational efficiency and to
9 improve employee and customer experience. Implementation plans have not yet been
10 developed.
11 vi) Hydro Ottawa utilizes an eco-system of partners and has taken a proactive approach to
12 vendor management that includes thorough market research on vendor solutions,
13 strategic contract planning and negotiations to minimize financial increases from its
14 suppliers. Most cloud software vendors have economic adjustments to subscriptions
15 which naturally increase overtime. Hydro Ottawa does its best to keep these fees at a
16 reasonable threshold but ultimately inflationary increases are anticipated at the time of
17 contract renewal.
18 vii) This is primarily due to inflationary increases to software subscriptions. Software
19 vendors have increased subscription fees, often citing inflation, enhanced features
20 (especially AI integration), and a shift away from perpetual licenses - a challenge which
21 Hydro Ottawa continues to manage.
22
23 f) Table B lists Hydro Ottawa's major subscription costs for 2021-2026. The threshold applied to
24 'major' subscription costs are those with an annual cost of \$0.2M or more as of 2024 onwards.
25 Therefore, it should be noted that Table B below is not an exhaustive list of major subscription
26 costs.

Table B - Major Subscription Costs (\$'000s)

Subscription	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
CC&B	\$ 229	\$ 232	\$ 209	\$ 243	\$ 243	\$ 243
Workplace tools	\$ 287	\$ 219	\$ 263	\$ 263	\$ 263	\$ 653
Software integrations	\$ 130	\$ 117	\$ 228	\$ 357	\$ 375	\$ 525
HR	\$ 379	\$ 415	\$ 509	\$ 481	\$ 500	\$ 500
Salesforce	-	\$ 408	\$ 508	\$ 533	\$ 605	\$ 635
Vegetation Management	-	\$ 62	\$ 300	\$ 315	\$ 331	\$ 347
Cybersecurity	\$ 43	\$ 194	\$ 311	\$ 320	\$ 320	\$ 650
TOTAL	\$ 1,069	\$ 1,646	\$ 2,327	\$ 2,513	\$ 2,636	\$ 3,553

1

2

3 g) IT initiatives with cost savings expected in the forecast period (such as the Customer
 4 Relationship Management system) are detailed in Section 3.2 of Schedule 1-3-4 - Facilitating
 5 Innovation and Continuous Improvement. Other initiatives (such as AI-driven solutions) will not
 6 see cost savings until the outer years of the rate period and therefore are not reflected in this
 7 application.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-151**

4
5 **EVIDENCE REFERENCE:**

6
7 Safety, Environment & Business Continuity OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 53-55 (pdf pp. 94-96)

9 Ref. 2: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / Table 9 / p. 32 (pdf p. 218)

10
11 **QUESTION(S):**

12
13 a) Please explain the reason(s) for the \$952k increase (36%) in 2024 compared to 2023 (Table 22
14 in reference 1).

15 b) Please explain the four new positions being hired for 2026 and one for 2028, including their
16 roles and responsibilities as shown in reference 2.

17 c) Please explain the considerations made in hiring all four positions in 2026 rather than spreading
18 out hiring through the five-year period.

19
20
21 **RESPONSE(S):**

22
23 a) The main driver for the increase of \$952k from 2023 to 2024 is a planned increase in training,
24 as some training was delayed from 2023 due to the strike. The increase is also explained by the
25 additional positions added in 2024.

26
27 b) Attachment 4-1-3(E) - Health, Safety and Environmental Compliance, Sustainability and
28 Business Continuity Management describes rationale for five new positions. These positions
29 include one Manager, Sustainability; two Sustainability Specialists; one Business Continuity
30 Specialist and one Instructional Designer. This response addresses the questions asked in parts
31 b) and c).

1 1. Sustainability: Two of the four new positions in 2026 will directly support Hydro Ottawa’s
2 commitment to sustainability and efforts related to Hydro Ottawa Holding’s net-zero
3 operations target, a significant portion of which relates to utility activities. As noted in
4 Schedule 1-6-1 - Corporate Structure and Governance, Hydro Ottawa Holding Inc. is the
5 parent company of Hydro Ottawa Limited.

6
7 As described in Attachment 4-1-3(E) - Health, Safety and Environmental Compliance,
8 Sustainability and Business Continuity Management, subsequent to Hydro Ottawa
9 Holding Inc. declaring its net-zero goal, the utility went through multiple significantly
10 disruptive events, including the derecho in 2022 and an 84-day strike in 2023. These two
11 disruptions had wide-reaching impacts and diverted resources from areas of the
12 business that did not involve core operational activities, including sustainability. In light of
13 the disruptive events where sustainability resources were redeployed, the desired level
14 of progress against plans was not fully achieved.

15
16 These new Sustainability Specialist positions will provide resources dedicated to and
17 focused on sustainability. To date, sustainability efforts have included researching and
18 implementing appropriate methodologies, quantifying emissions, developing preliminary
19 actions, providing advisory support and expertise to internal functions, and cataloguing
20 initiatives in progress. These two roles are necessary to provide the required focus in
21 2026, with the utility’s business activity set to expand considerably during the 2026-2030
22 rate term and with sustainability set to remain an ongoing area of focus for the
23 2026-2030 strategic planning window. The responsibilities of these positions will include
24 developing action plans to re-affirm or refresh the methodology and approach to
25 net-zero; coordinating the establishment and monitoring of measures across functions
26 and activities where feasible; developing new actions based on additional research and
27 the strategic direction for 2026-2030; strengthening the expertise made available to
28 internal functions; identifying and promoting synergies between the utility’s own net-zero
29 activities and potential service offerings for customers; and facilitating internal and
30 external communications.

1 The Manager, Sustainability role is planned for 2028, as it is anticipated that additional
2 leadership and coordination capacity will be required as the scope of
3 sustainability-related activity expands and increases in complexity.

4
5 As the net-zero goal is one established at the holding company level and applies across
6 subsidiaries, costs of these positions will be allocated through service level agreements
7 to non-utility entities.

8
9 2. Business Continuity: As described in Attachment 4-1-3(E) and the foregoing response
10 for part (b), the type, severity, frequency and duration of disruptive events between 2018
11 and 2023 provided the basis for the formation of a new position, Manager, Business
12 Continuity Management in 2024 as well as a Business Continuity Specialist - Electrical
13 Emergency Response Plan. This provided the resources necessary to renew, update,
14 coordinate training to additional resources and provide ongoing monitoring and
15 maintenance of plans related to electrical emergencies. These positions established the
16 first part of a foundation to re-examine business continuity planning assumptions and
17 provide dedicated resources in an increasingly disruptive and complex operational
18 environment, with changing hazards and risks. Adding one additional Business
19 Continuity Specialist in 2026 aligns with and supports increased planning and
20 preparation to the utility to support continuity of service regardless of the type of event.
21 This position's responsibilities will include conducting business impact analyses,
22 facilitating planning, response and recovery activities with functional activity owners as
23 well as after action reporting with the goal of continual improvement and strengthening
24 organizational resilience.

25
26 The Instructional Designer role currently planned for 2026, is required as more training
27 specific to the utility and its operations is expected, particularly in the areas of safety and
28 business continuity. As outlined in Attachment 4-1-3(E), with the continued demographic
29 shift and introduction of employees with less experience in the trade and/or less
30 experience with Hydro Ottawa's system and work practices, the need for additional utility

- 1 specific training and more rigorous training is an important aspect in injury prevention
- 2 and organizational preparedness and response ability.
- 3
- 4 c) See response provided in part(b).

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-152**

4
5 **EVIDENCE REFERENCE:**

6
7 Human Resources OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / p. 55-57 (pdf pp. 96-98)

9 Ref. 2: HOL_Attachment 4-1-2(B) - OEB Appendix 2-JC-OM&A Programs Table_20250415.xlsx

10 Ref. 3: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / Table 11 / p. 36 (pdf pp. 222)

11
12 **QUESTION(S):**

- 13
14 a) Please explain in more detail the additional costs incurred in 2023 due to the labour strike that
15 contributed to the \$1.1M increase (reference 1).
16 b) Please explain the positions, including their respective roles and responsibilities, for the new
17 hire in 2024 and the two HR positions planned for 2026 as shown in reference 3.
18
19

20 **RESPONSE(S):**

- 21
22 a) Costs in the Human Resources program increased from 2022 to 2023 by \$1.1M predominantly
23 as a result of additional costs related to the 2023 labour strike including legal costs, such as the
24 injunction order, mediation fees, and security.
25
26 b) The position added in 2024 is a Human Resources Advisor. The positions planned for 2026 are
27 a Human Resources Advisor and a Human Resources Technology Specialist.
28

29 The Human Resources Advisor positions are being added to increase Hydro Ottawa's capacity
30 in relation to recruitment, onboarding and in ongoing employee and leadership support. The
31 Human Resources Advisor is the first point of contact for providing Human Resources services

1 to internal clients and is responsible for effectively resolving employee inquiries in a timely
2 manner and with considerable independence, discretion, judgment and initiative. The need for
3 increased capacity in this area is driven by recruitment and onboarding, employee and
4 leadership support and development, as well as the evolution of HR technology as described in
5 Section 3.4 of Attachment 4-1-3(C) - Workforce Growth.

6
7 The Human Resources Technology Specialist is required to support the ongoing development
8 and configuration and sustainment of HR technology platforms including Hydro Ottawa's Human
9 Resources Information System, Health and Safety systems, learning and development systems,
10 and more. The role is also responsible for the configuration and maintenance of security roles,
11 creation of reports and complex integrations to both internal and external systems, ensuring
12 privacy and protection of employee data. As a company that believes in providing employees
13 with the information they need, anytime, anywhere from any device, ensuring modern,
14 mobile-enabled HR technology systems is critical. This role will also be tasked with researching
15 new and innovative technologies to support ongoing digital transformation and the emergence
16 of AI in HR technologies. The need for increased capacity in this area is described in Section
17 3.4 of Attachment 4-1-3(C) - Workforce Growth.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-153**

4
5 **EVIDENCE REFERENCE:**

6
7 Supply Chain OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 57-59 (pdf pp. 98-100)

9 Ref. 2: HOL_Attachment 4-1-2(B) - OEB Appendix 2-JC-OM&A Programs Table_20250415.xlsx

10
11 **QUESTION(S):**

12
13 a) As part of its 2026-2030 Business Priorities for the program, Hydro Ottawa stated in reference 1
14 that it will leverage digital tools and data analytics to improve demand forecasting, inventory
15 optimization, and availability of materials while minimizing carrying costs. Does Hydro Ottawa
16 have any cost savings calculated for these initiatives. If so, please provide the amounts and
17 indicate where they have been incorporated into the 2026 forecast.

18
19
20 **RESPONSE(S):**

21
22 a) No, Hydro Ottawa does not have a separate, quantified estimate of cost savings for leveraging
23 digital tools and data analytics to improve demand forecasting, inventory optimization, and
24 materials availability.

25
26 However, the cost savings from these initiatives are embedded in our forecast. The benefits of
27 these digital tools, particularly the Enterprise Asset Management (EAM) system, are a key
28 reason why Hydro Ottawa's Supply Chain team is able to manage significant growth without
29 requesting additional headcount. The EAM system's capabilities will enable improved demand
30 forecasting and inventory optimization, thereby allowing the Supply Chain program to enhance

- 1 efficiency and minimize carrying costs with the current resource levels. Refer to Attachment
- 2 4-1-1(A) - Transition to Cloud Computing for more information on the EAM system.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-154**

4
5 **EVIDENCE REFERENCE:**

6
7 Facilities OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / p. 59-60 (pdf p. 100-101)

9
10 **QUESTION(S):**

- 11
- 12 a) Aside from security costs, what other strike-related costs were incurred in 2023 in relation to the
- 13 \$3.9M increase.
- 14 b) How many days was strike-related security hired for?
- 15 c) Please confirm amount, percentage increase, and the reason for the increase in insurance
- 16 payment in 2024. Is this expected to continue in the forecast years?
- 17 d) Please provide the cost and explain the scope for the consultant for the environmental initiatives
- 18 work done in 2024.
- 19 e) Does Hydro Ottawa have any cost savings estimated with regards to the initiatives stated in
- 20 reference 1 (e.g. energy efficiency and flexible and well-maintained workspaces)? If so, please
- 21 comment whether have they have been incorporated the 2026 forecast and where they are
- 22 located in the application?
- 23
- 24

25 **RESPONSE(S):**

- 26
- 27 a) Aside from security costs, the strike-related costs included vehicle rentals, fencing and barriers,
- 28 lock boxes, management shuttle costs, courier and mail deliveries, AZ drivers for bucket trucks,
- 29 office space rental, security camera rentals, security mobile patrols, lodging for out of town
- 30 contractors and labour disruption planning consulting services.
- 31

- 1 b) Strike-related security was hired for the duration of the 84-day strike, and a few resources were
2 retained in the planning stage as well as some close-out activities.
3
- 4 c) There was an increase in insurance costs in 2024 of \$0.5M which represents a 39% increase.
5 The increase was as a result of higher property insurance premiums levied by Hydro Ottawa's
6 property insurer, driven by inflationary increases in the replacement cost of Hydro Ottawa's
7 insured assets, combined with an increase in the premium rate. While property insurance
8 premium increases of this magnitude are not expected to persist in the forecast years, property
9 insurance premiums undoubtedly are expected to increase driven by continued inflationary
10 increases in the replacement cost of Hydro Ottawa's insured assets as well as the construction
11 of new substations and the planned upgrades for existing stations, as described in Schedule
12 2-5-1 - Distribution System Plan Overview.
13
- 14 d) The costs included in the 2024 Bridge Year that was attributed to the consultant for the
15 environmental initiatives work was \$0.4M. The scope of work included a building assessment to
16 evaluate current energy consumption, building systems, and infrastructure at four of Hydro
17 Ottawa's facilities. The goal was to identify opportunities to transition to more sustainable,
18 environmentally friendly energy sources. The consultant also conducted a study that focused on
19 the infrastructure required to support fleet electrification, including an analysis of charging
20 infrastructure, energy and capacity requirements, various charging scenarios, and the budgeting
21 for necessary facility upgrades.
22
- 23 e) No, Hydro Ottawa does not have a separate estimate of cost savings associated with energy
24 efficiency and flexible, well-maintained workspaces, as these savings are already built into the
25 facilities budget. These practices are a fundamental part of the facilities program, and the
26 resulting cost savings are reflected in both historical actuals and the 2026 forecast. The
27 program's preventative maintenance approach, which has long been proven to be more
28 cost-effective than a reactive "run to failure" model, is key to keeping reactive costs low.
29 Additionally, the use of a modular furniture system allows for efficient in-house reconfigurations,
30 eliminating the need to budget for costly external contractors. Furthermore, upgrades to improve

- 1 energy efficiency have reduced operational costs, and these savings are also reflected in the
- 2 forecast.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-155**

4
5 **EVIDENCE REFERENCE:**

6
7 Finance OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 60-62 (pdf pp. 101-103)

9 Ref. 2: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / p. 39 (pdf p. 225)

10
11 **QUESTION(S):**

- 12
- 13 a) Given that the compensation is the primary cost driver and the headcount within the program
14 has remained relatively flat over the past four years (lines 12-14 in reference 1), please explain
15 the 16% decrease in the program cost in 2024.
- 16 b) Please describe the complexity and evolving requirements noted in reference 2 (lines 14-17)
17 that led to the required increase in Finance staff.
- 18 c) Please explain the new position hired in 2024, as well as the three positions planned for 2027
19 through 2029, including their respective roles and responsibilities as shown in reference 2 (table
20 12).

21
22
23 **RESPONSE(S):**

- 24
- 25 a) The 15.6% decrease in finance costs from 2023 to 2024 is largely due to an increase in costs
26 allocated from the billing function within finance to services to third parties and customer billing
27 following a recent review, as noted in Section 4.3 of Schedule 6-3-1 - Other Revenue Summary.
28 The result of the review determined that the billings team within the finance group processed a
29 significant amount of WFO billings which are actually third party costs hence the revision to the
30 allocation.

- 1 b) The complexity and evolving requirements noted in reference 2 (lines 14-17) are provided at the
2 same reference, beginning on line 21. These factors include:
- 3 ● Increased Capital and OM&A Activity: Hydro Ottawa's capital program is nearly doubling in
4 size, resulting in a substantial increase in financial transactions that require processing,
5 analysis, and reporting.
 - 6 ● Increased Complexity: New initiatives, such as cloud computing and non-wires alternatives,
7 introduce significant accounting complexity. For example, cloud computing acquisitions now
8 require in-depth analysis against complex accounting rules.
 - 9 ● Evolving Reporting Requirements: The emergence of new Environmental, Social and
10 Governance (ESG) reporting standards and evolving regulatory reporting requirements
11 necessitate additional resources for data collection, analysis, and reporting.
 - 12 ● Financial Resilience: The organization's evolving risk profile, driven by more frequent
13 extreme weather events, requires robust financial oversight, detailed accounting for
14 storm-related costs, and strengthened internal controls.

- 15
16 c) The new positions are required to manage the increase in the volume and complexity of work
17 within the finance functions, as well as to establish a new regulatory finance focused position.
18 Due to the level of experienced and expected growth, the scope and demands of each portfolio
19 have expanded, meaning that what has historically been a manageable portfolio with the
20 existing resources has effectively become larger and more complex. As a result, existing staff
21 can no longer manage their previous portfolios effectively within their areas of responsibility. The
22 new positions will allow the finance organization to distribute the workload differently, ensuring
23 that all financial duties can be performed accurately and in a timely manner.

24
25 A new accountant position was added in 2024 to address immediate escalating demands.
26 Subsequently, one additional position is planned for each of 2027, 2028, and 2029. Of these
27 three positions, two are planned as accountant roles to handle the increased volume, while one
28 will be a dedicated Regulatory Finance Specialist.

29
30
31

- 1 The responsibilities for these positions include, but are not limited to, the following core duties:
- 2 ● Financial Reporting and Analysis: Preparing a full range of financial documents, from annual
3 budgets to mid- to long-term forecasts and seven-year budgets for regulatory filings;
4 quarterly forecasts, and monthly financial actual to budget reports; analyzing variances; and
5 providing recommendations to management.
 - 6 ● Regulatory Finance: A new position planned for the 2027-2029 period will serve as a
7 dedicated Regulatory Finance Specialist. During the intensive rate application years (two out
8 of every five), this individual will lead the finance team through forecasting, evidence writing,
9 training, and interrogatories. In the remaining three years, this role will continuously monitor
10 regulatory requirements and their financial impact, track progress against plans, document
11 variances, conduct additional analysis requested by working groups (e.g., benchmarking),
12 and act as the key liaison between the regulatory and accounting teams. This ensures the
13 team remains continuously prepared and knowledgeable, rather than needing to ramp up
14 every five years.
 - 15 ● Accounting and Compliance: Performing month-end close processes, preparing journal
16 entries, and ensuring compliance with evolving accounting standards and regulations.
 - 17 ● Capital Assets and Projects: Providing financial oversight, guidance, and training on capital
18 projects. This includes managing work orders, preparing budgets and regulatory filings, and
19 providing oversight on the complex criteria that determine whether a cost is capitalized or
20 expensed.
 - 21 ● Project Billing and Contracts: Setting up and maintaining records for contracts and project
22 billing; processing and issuing invoices for project work; monitoring and analyzing project
23 costs and payments; and researching and resolving billing issues.
 - 24 ● System and Process Improvements: Providing recommendations on system improvements
25 to drive efficiencies and data integrity.
 - 26 ● Management and Support: Providing effective support to operational teams, strengthening
27 internal controls and risk management, and offering hands-on training and coaching to new
28 leaders and larger teams to ensure the maintenance of proper records and adherence to
29 company policies.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-156**

4
5 **EVIDENCE REFERENCE:**

6
7 Corporate Costs OM&A Program

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 2 / pp. 64-66 (pdf pp. 105-107)

9 Ref. 2: HOL_Attachment 4-1-2(B) - OEB Appendix 2-JC-OM&A Programs Table_20250415.xlsx

10
11 **QUESTION(S):**

12
13 a) Please explain in further detail the corporate function activities related to the strike and storm in
14 2023 that contributed to the increase in costs of \$1.5M.

15
16
17 **RESPONSE(S):**

18
19 Hydro Ottawa experienced a \$1.5 million increase in corporate functions in 2023 as a result of the
20 strike and storm-related activities as noted in reference 1. The demand for executive management
21 time significantly increased in 2023 due to the 84-day strike in 2023 and increased storm activity in
22 the same year. For a list of significant storm activity, refer to Table 4 - Historical Weather Events and
23 Impacts outlined in Schedule 2-5-1 - Distribution System Plan Overview.

24
25 Subsequent to the devastating 2022 Derecho, the heightened sensitivity to storms and power
26 outages necessitated an increased need for proactive executive management, including enhanced
27 communication with customers and city councillors, particularly during the strike when a significant
28 portion of the management team was performing front-line work. Furthermore, during the 84-day
29 strike, the executive management team was critically focused on ensuring work continuity, assisting
30 the rest of the management staff with managing the workload, and actively participating in labour

1 relations efforts. A significant amount of time was also dedicated to pre-strike planning and labour
2 relations in proactive efforts to avert the strike, as well as post-strike labour relations.
3
4 Beyond these specific 2023 events, the demand for executive management time has also increased
5 due to broader strategic imperatives. Lessons learned from the strike underscore the need for
6 management to prioritize employee engagement, safety and well-being. Furthermore, the
7 substantial rise in large load connection requests and inquiries, coupled with the changing
8 regulatory landscape, evolving energy security priorities, climate change implications, and the
9 ongoing digital transformation of the industry, all necessitate greater executive oversight. These
10 complex factors have, in turn, also necessitated an increase in corporate support across various
11 functions, including services such as Internal Audit. Please refer to Section 4.1 of Schedule 4-2-1 -
12 Shared Services and Corporate Cost Allocation for details on the methodology used to allocate
13 executive support.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-157**

4
5 **EVIDENCE REFERENCE:**

6
7 Merit Increases

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment 1 / pp. 3-4 (pdf pp. 131-132)

9
10 **QUESTION(S):**

- 11
12 a) Please provide sources of information that Hydro Ottawa used to forecast its merit increases for
13 management and non-union employees.
- 14 b) Please provide a table that shows the salary projections for the utility and broader public
15 sectors, and consumer price indices that Hydro Ottawa used to determine the merit increases
16 (during the historic period) as well as the resulting merit increase associated with each
17 performance rating. Please comment on whether the merit increases are aligned with these
18 projections.

19
20
21 **RESPONSE(S):**

- 22
23 a) Tables A-D below include all sources of information that Hydro Ottawa used to forecast its merit
24 increases for management and non-union employees listed. The forecast for 2026 is based on
25 current trending, collective agreement increases and anticipated CPI.
- 26
27 b) Tables A-D show the salary projections for the utility and broader public sectors, and consumer
28 price indices that Hydro Ottawa used to determine the merit increases (during the historic
29 period). Table E details the merit increases for the associated years. Merit increases are based
30 on overall performance level for the given year. Increases are aligned with the corresponding

- 1 annual forecasts in tables A-D. The asterisks in each table (A through D) denote information
- 2 that was not available at the time of reporting / analysis.

1 **Table A - 2024 Salary Projection Sources**

2024														
	Telus Health	Korn Ferry Hay Group		Willis Towers Watson		Mercer	Eckler Ltd.	Normandin Beaudry	World at Work			Statistics Canada	Bank of Canada	
	Non-Unionized Employees	Industry Sector	Executives	All	Executives	All	All	Non-Unionized Employees	All	Officers/Executives	Management Salaried	All-Items CPI	Total CPI	CPIX
Canada	3.64%	3.90%	4.00%	3.80%	3.70%	3.30%	3.90%	3.60%	3.80%	3.70%	3.90%	3.80%	3.80%	2.80%
Ontario	3.64%						3.70%	3.60%				3.60%		
Ottawa												2.90%		
Private sector*														
Utilities	3.30%			3.80%				3.50%						

2 *Data not available at time of reporting

1 **Table B - 2023 Salary Projection Sources**

2023											
	LifeWorks (previously Morneau Shepell)	Korn Ferry Hay Group	Willis Towers Watson		Mercer	Eckler Ltd.	Normandin Beaudry	Conference Board of Canada	Statistics Canada	Bank of Canada	
	Non- Unionized Employees	All	All	Executives	All	All	Non- Unionized Employees	Non- Unionized Employees	All-Items CPI	Total CPI	CPIX
Canada	3.93%		3.70%	3.80%	3.50%	4.20%	3.80%	3.40%	6.90%	6.90%	6.00%
Ontario	3.82%					4.10%	3.90%	3.30%	6.70%		
Ottawa									6.80%		
Private sector								3.50%			
Utilities	3.05%		3.80%			3.70%	3.30%	3.00%			

2

1 **Table C - 2022 Salary Projection Sources**

2022											
	LifeWorks (previously Morneau Shepell)	Korn Ferry Hay Group	Willis Towers Watson		Mercer	Mearie	Normandin Beaudry*	Conference Board of Canada	Statistics Canada	Bank of Canada	
	Non- Unionized Employees	All	All	Executives	All	All	Non- Unionized Employees	Non- Unionized Employees	All-Items CPI	Total CPI	CPIX
Canada	2.70%	1.80%	2.80%	2.70%	2.60%			2.60%	4.40%	4.40%	3.70%
Ontario	2.50%										
Ottawa*											
Private sector*											
Utilities	2.40%					2.20%					

2 *Data not available at time of reporting.

1 **Table D - 2021 Salary Projection Sources**

2021											
	LifeWorks (previously Morneau Shepell)	Korn Ferry Hay Group	Willis Towers Watson		Mercer	Mearie*	Normandin Beaudry*	Conference Board of Canada	Statistics Canada	Bank of Canada	
	Non- Unionized Employees	All	All	Executives	All	All	Non- Unionized Employees	Non- Unionized Employees	All-Items CPI	Total CPI	CPIX
Canada	1.90%	1.80%	2.00%	2.00%	1.90%			2.10%	1.00%	1.00%	1.50%
Ontario	2.00%								0.90%		
Ottawa									1.80%		
Private sector*											
Utilities	2.40%										

2 *Data not available at time of reporting.

1 **Table E - Historical Merit Increases**

Employee Group	Improvement Required	Partial Achievement	Successful Achievement	Exceeds Achievement	Year
Non-Union	0%	0% - 1.0%	2.30%	2.4% - 4.5%	2021
Management	0%	0% - 1.0%	1.75%	2.0% - 3.0%	
Non-Union	0%	0% - 1.0%	2.75%	2.75% - 4.75%	2022
Management	0%	0% - 1.0%	2.50%	2.5% - 3.25%	
Non-Union	0%	0% - 1.0%	2.50%	2.5% - 5.0%	2023
Management	0%	0% - 1.0%	2.50%	2.5% - 3.5%	
Non-Union	0%	0% - 2.0%	3.5% - 3.8%	3.8% - 5.5%	2024
Management	0%	0% - 2.0%	3.5% - 3.8%	3.85 - 4.5%	

2

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

4-Staff-158

EVIDENCE REFERENCE:

Incentive-Based Pay

Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment 1 / pp. 4-5 / (pdf pp. 132-133)

QUESTION(S):

a) Table 2 in the reference shows the average annual incentive-based pay (\$) for the 2021 to 2023 period for senior management positions and members of the executive team. Please provide the average annual incentive-based pay as a percentage of the average annual salary for senior management and the executive team for each of the years.

RESPONSE(S):

a) Table A provides the requested data.

Table A - Average Annual Incentive-Based Pay

	2021	2022	2023
Employees	38	39	43
Average Incentive	\$ 18,818	\$ 18,701	\$ 18,388
Average Annual Salary	\$ 124,183	\$ 126,095	\$ 128,332
Average Incentive as Percent of Average Annual Salary	15.2%	14.8%	14.3%

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-1**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / p. 10 (pdf p. 138 of pdf)

8
9 **QUESTION(S):**

10
11 a) Please provide a breakdown of the Pension and OPEB amounts between capital and OM&A
12 from the last OEB-approved to 2030, for each year.

13
14 _____
15 **RESPONSE(S):**

16
17 Please note that the reference should point to Exhibit 4 / Tab 1 / Schedule 3 / Attachment A / P. 10.

18
19 a) Hydro Ottawa's pension and OPEB amounts are not directly broken down between capital and
20 OM&A. Instead, these costs are integrated into the overall labor rate calculation. The labor
21 costs, which include a portion of pension and OPEB, are then charged to capital projects or
22 OM&A based on employee time entries.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-159**

4
5 **EVIDENCE REFERENCE:**

6
7 OM&A - New Positions

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / Table 1 / p. 3 (pdf p. 189)

9
10 **QUESTION(S):**

11
12 a) Please explain how Hydro Ottawa determined the number of new positions required for each
13 OM&A Program in Table 1 for 2024 and for the 2026-2030 period.

14 i) Please provide any underlying calculations to support how the new positions were
15 determined in 2024 and for the 2026-2030 period.

16 ii) Please provide job titles and the number of new positions associated with each title in a)
17 i.

18
19
20 **RESPONSE(S):**

21
22 a) The approaches used to determine new positions required are described in Attachment 4-1-3(B)
23 - Workforce Planning Strategy pages 18-19.

24
25 i) Trades: Trades Workforce Planning is completed annually for the proposed and
26 approved Work Programs for the subsequent year as described in Section 3.1.2 of
27 Schedule 4-1-3(B) - Workforce Planning Strategy. The general approach used to prepare
28 trade volumes is further described in this Section on pages 18-19, but a simplified view
29 could be written as:

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Labour Supply Surplus/Gap = (Current and Planned Journeypersons - Forecasted Attrition) + (Current and Planned Apprentices) + (Forecasted Internal Overtime Utilization) + (Planned External Contracted Resources) - (Forecasted Labour Demand)

Using this approach, a Workforce Planning exercise was undertaken for a five (5) year period based on the work volumes expected within the Distribution System Plan (DSP). It is important to note that a five year forecast provides general work volumes, an annual Workforce Planning exercise is undertaken year-over-year to determine a more specific number of positions required in each trade.

Leadership & Non-Trades: The process followed for Non-Trade positions is outlined in Section 3.1.3 of Schedule 4-1-3(B) - Workforce Planning Strategy. Under this approach, current and future needs were reviewed relative to the Work Programs and drivers listed throughout Section 3 of Schedule 4-1-3(C) - Workforce Growth.

- ii) Table A below provides the job titles of the new positions associated with the OM&A programs.

The general work volumes included in the five year forecast as discussed in (i) use the best available data and information available at the time, however the specific hiring in each trade is reviewed and approved annually as more concrete work volume data becomes available. As such, trades positions under the Distribution Operations and Metering programs are included in Table A as “Direct Labour”, as the specific breakdown of the new trades positions is subject to change. These positions are generally at the same compensation level and therefore the allocation of positions do not impact compensation forecasts. To reiterate, while the general volume of work is forecasted at this time, greater specificity around the volume of work that will be assigned to specific trade positions is produced annually and informs annual hiring requirements.

1 Since the majority of positions are being added within Distribution Operations and
 2 Engineering & Design, these OM&A programs are further broken down between Direct
 3 Labour and Business Support, as shown in 4-1-3(C) - Workforce Growth on Table 5,
 4 page 15.

5
 6

Table A - Job Titles of New Positions by OM&A Program

Appendix 2-JC OM&A Program	Job Title	Year						Total
		2024	2026	2027	2028	2029	2030	
Metering	Direct Labour	3	3	2				8
Engineering & Design	Engineering							
	<i>Distribution Engineer</i>	3	5	6				14
	<i>Grid Modernization Engineer</i>	3	2					5
	<i>Quality Assurance Engineer</i>			1				1
	<i>Smart Grid Engineer</i>	4						4
	<i>Standards Engineer</i>	1						1
	<i>Telecommunications Engineer</i>	2						2
	Project Execution Planning							
	<i>Distribution Design Layout Agent</i>				2			2
	<i>Engineering Technologist</i>		1	3				4
	<i>Project Administrator</i>		2		1			3
	<i>Project Coordinator</i>		1	2			1	4
	<i>Work Planner</i>		3				1	4
	<i>Work Scheduler</i>		3					3
	<i>Resource Scheduling Agent</i>		1					1
	Leadership							

Appendix 2-JC OM&A Program	Job Title	Year						Total
		2024	2026	2027	2028	2029	2030	
	<i>Supervisor, Distribution Design Service Layout</i>				1			1
	<i>Supervisor, Distribution System Integration</i>	1						1
	<i>Supervisor, Engineering Technologists</i>			1				1
	<i>Supervisor, P&C</i>		1					1
	<i>Vice President</i>	2						2
	<i>Director, Program Management</i>	1						1
	<i>Supervisor, Distributed Energy Resources</i>		1					1
	<i>Supervisor, Major Projects</i>		1					1
	<i>Supervisor, Program Oversight</i>		1					1
	Direct Labour	22	27	19				68
Distribution Operations	System Operations							
	<i>Vault Maintenance Technical Specialist</i>		1					1
	<i>System Operations Planners</i>		2					2
	Contractor Management & Oversight							
	<i>Plant Inspector</i>		4					4
	<i>QA Inspector</i>		2					2
	<i>Utility Forestry Inspector</i>		1					1
	Leadership							

Appendix 2-JC OM&A Program	Job Title	Year						Total
		2024	2026	2027	2028	2029	2030	
	<i>Supervisor, Contractor Management</i>		1					1
	<i>Supervisor Control Room</i>		2					2
	<i>Supervisor, Stations</i>		1					1
	Engineering							
	<i>Project Engineer</i>		1	2				3
	<i>Data Engineer</i>		1					1
Customer Billing	<i>Programmer/ Analyst</i>		1					1
Customer & Community Relations	<i>Programmer/ Analyst</i>		1					1
Information Management & Technology	<i>Cloud Engineer</i>		1					1
	<i>Cybersecurity Engineer</i>	1	1					2
	<i>Manager, IT Program Management</i>	1						1
	<i>Manager, Systems Programs</i>		1					1
	<i>Supervisor, OT Cybersecurity</i>		1					1
	<i>System Engineer</i>		1					1
Safety, Environment & Business Continuity	<i>Business Continuity Specialist</i>	1	1					2
	<i>Instructional Designer</i>		1					1
	<i>Manager, Business Continuity</i>	1						1
	<i>Manager, Sustainability</i>				1			1
	<i>Sustainability Specialist</i>		2					2
Human Resources	<i>HR Advisor</i>	1	1					2

Appendix 2-JC OM&A Program	Job Title	Year						Total
		2024	2026	2027	2028	2029	2030	
	<i>HR Technology Specialist</i>		1					1
Finance	<i>Accountant</i>	1		1	1	1		4
Regulatory Affairs	<i>Advisor, Regulatory Compliance and Projects</i>	1						1
	<i>Supervisor, Regulatory Compliance and Projects</i>	1						1
Total		50	81	37	6	1	2	177

1

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-160**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / p. 6 (pdf p. 192)

8
9 **Preamble:**

10 Hydro Ottawa states that it experienced an unprecedented volume of customer driven growth
11 projects in the 2021-2025 period including the City of Ottawa's Zero Emission Bus project and the
12 Department of National Defence (DND) Dwyer Hill Road project which were not included in the
13 OEB-Approved 2021-2025 rate application.

14
15 **QUESTION(S):**

16
17 a) Please provide a table which shows a breakdown of OM&A costs per year for each of these
18 aforementioned projects as well as any other unforeseen projects which had an impact on
19 OM&A costs that were not included in the OEB-Approved 2021-2025 rate application.

20
21
22 **RESPONSE(S):**

23
24 a) The City of Ottawa's Zero Emission Bus and the DND Dwyer Hill Road project are capital
25 projects, as detailed in Section 4.3.2.1 of Schedule 2-5-6 System Access Investments and are
26 not categorized as OM&A projects.

27
28 Hydro Ottawa's workforce is planned to execute both capital and OM&A work as outlined in
29 Attachments 4-1-3(B) - Workforce Planning Strategy and 4-1-3(C) - Workforce Growth. Labour
30 costs are allocated to the appropriate capital program on an hourly basis or via burdens. For an
31 overview of unforeseen customer-driven growth projects that were not included in the

- 1 OEB-Approved 2021-2025 rate application, please refer to Schedule 2-5-5 Capital Expenditure
- 2 Plan.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-161**

4
5 **EVIDENCE REFERENCE:**

6
7 Customer Connection and Capacity Program Growth Headcount
8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / p. 7 (pdf p. 193)

9
10 Preamble:

11 Hydro Ottawa states that its decision to increase headcount in the Distribution Operations,
12 Engineering & Design, and Metering OM&A programs rather than leverage contracted resource was
13 informed by forward looking projections of capital and OM&A program increases for the 2026-2030
14 period and beyond.

15
16 **QUESTION(S):**

17
18 a) How did Hydro Ottawa determine that increasing the headcount is a more cost-effective option
19 than leveraging contracted services? Please explain in detail.

20
21
22 **RESPONSE(S):**

23
24 a) Hydro Ottawa would like to clarify that the reference of Section 3.1.1.1 of Schedule 4-1-3(C) -
25 Workforce Growth notes that Hydro Ottawa added 22 new positions as a result of the Customer
26 Connection and Capacity Growth driver. For more details on how Hydro Ottawa determines the
27 number of new positions, using both trades and non-trades workforce planning by driver, please
28 refer to 4-Staff-159.

29
30 Hydro Ottawa's strategy to staffing within the areas mentioned within the preamble is to
31 maintain internal headcount at a level that aligns with the lowest consistent workload,

1 supplementing peaks in both seasonal and individual programs with contracted resources. This
 2 is further represented by the fact that Hydro Ottawa’s proportion of spending on Outside
 3 Services remains relatively stable in the 2026-2030 period compared to 2021-2025, as shown in
 4 Figures 5 and 6 of Section 3.1.2.1 of Schedule 4-1-3(C) - Workforce Growth. The primary
 5 rationale for this approach is rooted in long-term financial analysis and a focus on business
 6 continuity. While contracted services offer flexibility, they come with a significantly higher billing
 7 rate compared to full-time employees (FTE). For illustrative purposes, Table A shows a
 8 comparative analysis between the hourly cost for an internal FTE, and the rate for a contracted
 9 journey person powerline technician.

10
 11 As shown in Table A, the cost differential is significant, averaging out at 27% variance between
 12 2025 and 2030. Beyond the direct cost, contracted resources present a higher risk of attrition,
 13 which can lead to a loss of institutional knowledge and productivity. The need for continuous
 14 retraining and re-staffing of key roles introduces operational inefficiencies and instability.
 15 Contracted resources also give Hydro Ottawa the flexibility to adjust staffing levels during slower
 16 periods without the expenses associated with full-time employees, allowing Hydro Ottawa to
 17 reduce overall costs.

18
 19 Given the company’s projections, which show that the growth in work volumes will extend
 20 beyond 2030, a permanent increase in headcount, while leveraging a consistent ratio of
 21 contracted services, is deemed the most strategic and cost-effective solution

22

23 **Table A - Comparative Wage Analysis**

Resource Type	2025	2026	2027	2028	2029	2030
Hydro Ottawa	92	95	98	101	104	107
Contracted Resource ¹	122.65	126.41	126.41	126.41	126.41	126.41
Variance	-30.65	-31.41	-28.41	-25.41	-22.41	-19.41
	33.32%	33.07%	28.99%	25.16%	21.55%	18.14%

24

¹ The contract in this analysis has a five-year term with prices held for the five-year duration upon negotiation.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-162**

4
5 **EVIDENCE REFERENCE:**

6
7 DER and Capacity Connection Request Complexity Headcount
8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / p. 9 (pdf p. 195)

9
10 **QUESTION(S):**

- 11
12 a) Please explain how Hydro Ottawa determined that four new Distribution Engineering positions
13 are required to respond to the increased volume and complexity related to DER and Connection
14 Requests in 2024.
- 15 i) Please provide any underlying calculations to support how the four new positions were
16 determined in 2024 if this information is not provided in response to 4-staff-159.
- 17 ii) Please provide job titles and the number of new positions associated with each title for
18 2024 if this information is not provided in response to 4-staff-159.

19
20
21 **RESPONSE(S):**

- 22
23 a) Hydro Ottawa followed the principles and approach outlined in Section 2 of Schedule 4-1-3 -
24 Workforce Staffing and Compensation to determine volumes of positions required for each Work
25 Program. Please see (i) and (ii) with regards to specific volumes of positions associated with
26 DER and Capacity Connection Request Complexity as described in Section 3.1.1.2 of
27 Attachment 4-1-3(C) - Workforce Growth.
- 28
29 i) From Figure 3 in Section 3 of Attachment 4-1-3(C) - Workforce Growth , there is an
30 increase of:
- 31
 - 29 large load requests (9 in 2021 to 38 in 2024) from 2021 to 2024, and

- 1 From Figure 4, there is an increase of:
- 2 • 143 (21 in 2021 to 163 in 2024) PCRs/CIAs from 2021 to 2024.
- 3
- 4 In 2021, HOL required the equivalent 0.75 of a position (three quarters of a Distribution
- 5 Engineering position's time) working on DER and Capacity Connection Requests. When
- 6 accounting for a general increase in complexity, this scales from 0.75 of a position in
- 7 2021 to 5 positions in 2024, requiring a new increase of 4 positions within Engineering &
- 8 Design.
- 9
- 10 ii) Please see response to interrogatory 4-Staff-159. The specific positions associated with
- 11 DERs are Distribution Engineer and Standards Engineer.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-163**

4
5 **EVIDENCE REFERENCE:**

6
7 Engineering Headcount

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / p. 10 (pdf p. 196)

9
10 **QUESTION(S):**

11
12 a) Please explain how Hydro Ottawa determined that ten new engineering positions are required to
13 support the implementation of the ADMS and on-going activities and projects related to the grid
14 modernization strategy in 2024.

15 i) Please provide any underlying calculations to support how the ten new positions were
16 determined in 2024 if this information is not provided in response to 4-staff-159.

17 ii) Please provide job titles and the number of new engineering positions associated with
18 each title for 2024 if this information is not provided in response to 4-staff-159.

19
20
21 **RESPONSE(S):**

22
23 a) The planning process for Non-Trade positions, detailed in Section 3.1.3 of Attachment 4-1-3(B) -
24 Workforce Planning Strategy, involved reviewing current and future needs against the Work
25 Programs and drivers listed in Section 3 of Attachment 4-1-3(C) - Workforce Growth. Further, an
26 organizational impact workshop was conducted specifically for the Grid Modernization
27 Roadmap. This exercise assessed various organizational structures, roles, and capacities. The
28 outcome determined that 10 positions are required for Grid Modernization, encompassing
29 ADMS and other elements of the Grid Modernization Strategy discussed in Section 3.4.2 of
30 Schedule 2-5-4 - Asset Management Process.

- 1 i) Per a) above, the general approach is described in Section 3.1.3 of Attachment 4-1-3(B)
2 - Workforce Planning Strategy.
3
- 4 ii) In reference to interrogatory 1-Staff-159, the titles associated with support the
5 implementation of ADMS and ongoing activities include:
6 • Four (4) Smart Grid Engineers
7 • Two (2) Telecommunications Engineers
8 • Three (3) Grid Modernization Engineers
9 • One (1) Supervisor, Distribution System Integration

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

4-Staff-164

EVIDENCE REFERENCE:

Benefits

Ref. 1: Exhibit 4 / HOL_Attachment 4-1-3(D) / Tab App.2-K_Employee Costs

QUESTION(S):

a) Please explain drivers of the year-over-year increase in benefit costs (row 24) from 2024 to 2026.

RESPONSE(S):

a) The cost drivers impacting benefit costs can be found in Attachment 4-Staff-167(A) - 2024 Anticipated Benefit Costs on page 3. Examples include inflation, specialty drugs, higher insurable earnings, etc.

Benefits as a percentage of total compensation are projected to remain consistent for the period of 2024 to 2026.

Table A - Benefits as a Percentage of Total Compensation, 2024-2026

Bridge	Bridge	Test
2024	2025	2026
22%	22%	22%

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-165**

4
5 **EVIDENCE REFERENCE:**

6
7 Total Compensation for Management

8 Ref. 1: Exhibit 4 / HOL_Attachment 4-1-3(D) – OEB Appendix 2-K _ Employee Costs_20240415

9 Ref. 2: Exhibit 4 / Tab 3 / Attachment A / pp. 14-15 (pdf pp. 142-143)

10
11 Preamble:

12 In reference 1, the total compensation amount for management increased by \$4.1M in 2023 while
13 the number of FTEs for management increased by 1.

14
15 Reference 2 states that total compensation for management is higher in 2023 due primarily to
16 overtime worked during the period of the strike responding to outages resulting from an
17 exceptionally active summer of lightning strikes, tornados, and heat waves.

18
19 **QUESTION(S):**

- 20
21 a) Please provide the total compensation increase amount in 2023 as a result of overtime work by
22 management employees noted above.
23 b) Please explain the main drivers of the increase.
24 c) Please explain or provide a copy of the overtime work agreement for management employees.

25
26 _____
27 **RESPONSE(S):**

- 28
29 a) Total cost of overtime for management employees was \$2,766,875.

1 b) The main driver of the increase in overtime in 2023 is directly attributable to the labour
2 disruption that occurred from June 28, 2023 to September 19, 2023. During this period,
3 management employees, particularly those in operations, were responsible for ongoing
4 operations of the utility. In addition, as stated in Attachment 4-1-3(A) - Employee Compensation
5 Strategy pages 14-15, 2023 was also an exceptional year for extreme weather from storms,
6 lightning strikes and heat waves which required teams to respond to emergency calls due to
7 storm related damage, accidental damage and infrastructure failure. Given that we require 24/7
8 coverage, and had a limited number of non unionized operational employees that had the
9 necessary skills, experience and qualifications/certifications to perform this work in a safe
10 manner for both the employee and the public, rotational shifts were implemented and payment
11 of overtime was necessary. In addition, a number of non-operational management employees
12 were redeployed or performed multiple duties during the disruption and worked overtime hours
13 but to a lesser extent.

14

15 c) As per our Terms and Conditions of Employment for Full-time Regular Management Group
16 Employees, the following statements direct our overtime allowances:

17

18 Emergency overtime - Non union employees and Supervisors¹ are eligible for emergency
19 overtime pay or time off in lieu for work outside of normal working hours at two times their hourly
20 rate of pay.

21

22 Non-emergency overtime - Non union employees and Supervisors² are eligible for
23 non-emergency overtime pay or time off in lieu at two times their hourly rate of pay for
24 pre-authorized, non-emergency overtime to complete pre-scheduled projects that cannot be
25 performed during normal hours of work.

¹ At the time of the strike some managers were also eligible for emergency overtime.

² At the time of the strike some managers were also eligible for non-emergency overtime.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-166**

4
5 **EVIDENCE REFERENCE:**

6
7 Wages and Salaries

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Section 2.4 / p. 5 (pdf p. 133)

9
10 **QUESTION(S):**

11
12 a) Reference 1 only shows wage increases for unionized employees. Please provide an average
13 annual salary increase (in %) for management employees per year from 2021 to 2026.

14
15 **RESPONSE(S):**

16
17 a) Management wage increases for the period January 1, 2021 to December 31, 2026 will be on
18 average 3.3% per year. The Consumer Price Index from October 2021 to October 2024 has
19 risen by an average annual rate of 3.99%, while management wages at Hydro Ottawa during
20 the same period increased by an average of 3.07% per year.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-167**

4
5 **EVIDENCE REFERENCE:**

6
7 **Benefit Costs**

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment A / Table 9 / p. 15 (pdf p. 143)

9
10 **QUESTION(S):**

11
12 a) Reference 1 states that Hydro Ottawa projected its benefit costs using assumptions based on
13 Mercer's 2024 Anticipated Benefit Costs published in fall 2023. Please provide a copy of
14 Mercer's 2024 Anticipated Benefit Costs.

15 b) Please explain the assumptions used to project Hydro Ottawa's benefit costs for 2024-2026.
16
17

18 **RESPONSE(S):**

19
20 a) Please see Attachment 4-Staff-167(A) - 2024 Anticipated Benefit Costs.

21
22 b) The assumptions used to project Hydro Ottawa's benefits costs from 2024-2026 reflect Mercer's
23 best estimates of rate changes subject to any rate guarantees and caps in place from the
24 competitive marketing process undertaken in late 2022 and early 2023, as stated in Section 2.6
25 of Attachment 4-1-3(A) - Employee Compensation Strategy.

26
27 The assumptions take into account the recent experience of the Hydro Ottawa group plan, and
28 Mercer's 2024 Anticipated Benefits Costs provided as Attachment 4-Staff-167(A) - 2024
29 Anticipated Benefit Costs. The assumptions take into account various cost drivers that are
30 prevalent in the current environment. Below is a listing of assumptions for the major benefits
31 offered.

1 Health and Dental assumptions are based on Hydro Ottawa's size and claims history, with plan
2 utilization and inflation used to determine future cost. It should be noted that plan maximums for
3 services have been implemented on both Health and Dental plans, decreasing the effects of
4 inflation to a degree. Hydro Ottawa has assumed 5.5% to 6.5% increase to Dental and 7.5%
5 decreasing to 6.2% for Health costs for the period.

6
7 OMERS pension assumption is tied to increases in YMPE (Year's Maximum Pensionable
8 Earnings) and cost tied to base salary of employees. OMERS Sponsors Corporation has
9 announced that rates for 2024, 2025 and 2026 will remain unchanged at 9% on earnings up to
10 YMPE and 14.6% on earnings above YMPE. In 2027, the rates will be 8.6% on earnings up to
11 YMPE and 15.7% on earnings above YMPE. We have included this in our assumptions as well
12 as projections to increases in YMPE for 2024 onwards.

13
14 The employers' portion of CPP has been historically stable. Rates for CPP first ceiling have
15 been projected to remain at 5.95% of earnings up to YMPE for the period. We have
16 incorporated the second CPP ceiling into our assumptions; however, we have anticipated the
17 rate of 4% to remain static. As mentioned above, both the YMPE and the second earnings
18 ceiling have been forecast to increase.

2024 Anticipated Benefit Costs

Private Benefit Plans

October 2023

A business of Marsh McLennan

1. This document offers Mercer projections with respect to changes in private employer benefit plan costs.
2. Budgets are guidelines only. In many cases, organizations can experience substantially higher increases, particularly for the first renewal after the expiry of any marketing rate guarantees. Projections for any particular plan will vary based on claims experience, demographics, plan design, etc.
3. This information is intended to assist with budget projections for 2024.
4. Unless otherwise noted, the information provides projections only with respect to changes in private employer benefit plan costs for the upcoming year.

Introduction

Cost drivers impacting 2024 trends

2024

Disability incidence still high

Specialty drugs, including for new rare diseases and gene therapies

Chronic diseases

Dental fee guides

Expected average renewal increase of 7% to 10%

Higher insurable earnings

Inflation

Diabetes & weight loss drugs

Delays in treatment

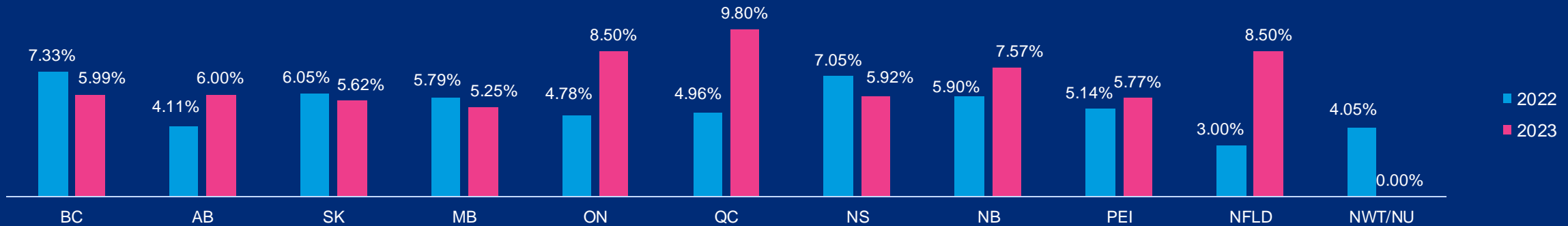
Lower expected reserves due to rising interest rates

Transition to biosimilar drugs

Reasonable & Customary limits and maximums included in programs

Maximums included in provisions

Annual adjustments – Dental fee guide by province



Basic life insurance

Premium adjustments are specific to the group and influenced by:

- Change in demographics
- Manual rates
- Plan experience (death claims, disability waivers) – to the extent credible
- Reserve requirements
- Plan design
- Budgeting should consider the impact of increased volume due to headcount or salary increases in addition to the projected rate increase

**Projected rate
increase:
0% - 5%**

CURRENT ENVIRONMENT

- There are no significant changes with respect to mortality expectations.
- Demographic changes (i.e. aging of the workforce) may also be slowing for some employers, or in some cases reversing as employers experience retirement activity.
- Continued interest rate increases should result in more favourable waiver of premium reserves and, to a lesser extent, manual rates.
- For earnings-based life insurance, higher salary increases in this inflationary environment should be incorporated into the projection of premiums for 2024.

Short and Long Term Disability

Premium/cost adjustments are specific to the group and influenced by:

- Change in demographics
- Manual rates
- Plan experience (incidence & duration of disabilities) – to the extent it is credible
- Reserve requirements
- Plan design
- Budgeting should consider the impact of increased volume due to headcount or salary increases in addition to the projected rate increase

**Projected rate
increase:
5% - 15%**

CURRENT ENVIRONMENT

- LTD premiums continue to be impacted by higher disability incidence, primarily driven by mental health claims, but appear to be settling. With the higher proportion of mental health claims, preliminary data is suggesting higher rates of individuals not qualifying for the “any occupation” phase of the long-term disability, acting as a mitigating factor.
- With the economy on the verge of recession, studies have shown that downturns in economies lead to more favourable LTD experience.
- Continued interest rate increases should result in more favourable disabled life reserves and manual rates for LTD.
- Higher salary increases in this inflationary environment should be incorporated into the projection of STD and LTD premiums.

Extended health benefits

Per capita cost adjustments are based on:

- Plan utilization per type of services: drug, paramedical, vision, supplies and services
- Plan provisions that help insulate the experience from inflation (e.g. maximums)
- Market and organization-specific trend
- Change in reserves for insured plans
- Increases in stop-loss/pooling charges
- Budget projections for total costs should also consider variations in headcount in addition to the projected rate increase

**Projected rate
increase:
5% - 10%**

CURRENT ENVIRONMENT

- Recent Statistics Canada data is showing higher trend in the “Health Services” classification than general CPI; a reversal from last year. This may imply a “lag effect” of the high inflationary environment which, if true, would imply a longer return to normal healthcare inflation.
- Additional increases may apply if 2023 health rates were set too low.
- Prescription drug trend is increasing, and employer drug costs have continued to climb with high-cost drugs continuing to infiltrate the market. To mitigate increases, employers are advised to investigate:
 - The insurer’s biosimilar approach (new claimants only, mandatory switching, different approaches by population segments, etc.). Special attention should be given to the insurers 65+ strategy in provinces such as Ontario and Québec as private plans may find themselves becoming first payers
 - The insurer’s prior authorization approach with respect to Ozempic, Mounjaro, and Wegovy
 - What wellbeing supports are available in addition to drug coverage to support diabetes and weight loss

Dental benefits

Per capita cost adjustments are based on:

- Plan utilization
- Plan provisions that help insulate the experience from inflation (e.g. maximums)
- Provincial Dental Fee guide increases (not announced until early 2024)
- Budget projections for total costs should also consider variations in headcount in addition to the projected rate increase

**Projected rate
increase:
4% - 8%**

CURRENT ENVIRONMENT

- 2023 saw continued pressure from Fee Guide increases, with several provinces experiencing sharp increases in their 2023 Fee Guides.
- Consistent with general inflation, we expect Fee Guides increases will moderate for 2024, but not yet to their pre-pandemic levels.
- Note, higher dental rate increases may be required if 2023 rates were set too low.



Important Notices

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1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-168**

4
5 **EVIDENCE REFERENCE:**

6
7 Acquiring Talent, Demand Growth and Competitive Landscape for Talent

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment B / pp. 28-32 (pdf pp. 173-176)

9 Ref. 2: Exhibit 4 / Tab 1 / Schedule 3 / Attachment B / pp. 15-16 (pdf pp. 160-161)

10 Ref. 3: Exhibit 4 / Tab 1 / Schedule 3 / Attachment B / pp. 28-32 (pdf pp. 173-176)

11
12 **QUESTION(S):**

13
14 a) Given Hydro Ottawa’s effort in sustaining the trades (reference 1), please explain why there are
15 ongoing challenges to recruit apprentices for trades roles such as System Operator and Station
16 Electrician (reference 2). Is this due to the movement of employees to larger utilities for
17 increased compensation, different career opportunities, or for similar roles with reduced
18 workload (as stated in lines 24-26 of reference 1) or other reasons? Please explain.

19 b) Reference 2 states that the population in Ottawa has shown the highest growth rate and its
20 population is expected to increase by 15% from 2021 to 2031. This statement appears to
21 contradict another statement in reference 1 which states that an additional challenge for Hydro
22 Ottawa is the limited talent pool to draw from. Please explain why the talent pool is still limited.

23 c) Has Hydro Ottawa implemented any measures to determine the effectiveness of its recruitment
24 efforts stated in reference 3? If so, please explain or provide the resulting measures (if
25 available).

26
27
28 **RESPONSE(S):**

29
30 a) Unlike the Powerline Technician and Powercable Technician apprentice roles, where Hydro
31 Ottawa recruits candidates who have graduated from the Algonquin Powerline Technician

1 Diploma Program, there is not a defined program for Station Electricians and System Operators.
2 As such, Hydro Ottawa recruits from the broader marketplace and can be challenged to find
3 candidates with the education, skills and utility experience required in these roles. In the Ottawa
4 area, we do compete with a larger utility for these resources where salaries and numbers of
5 opportunities can be higher.

6
7 b) While the population of the Ottawa area is growing significantly, this does not directly translate
8 into a larger talent pool for highly specialized roles. The core issue is a skills mismatch and
9 intense competition. The population increase may be driven by various factors, such as families
10 seeking affordability or professionals from sectors with lower demand. However, the growth rate
11 of individuals with specific technical, engineering, and information technology skills—such as
12 cybersecurity analysts, electrical engineers, or AI specialists—is not keeping pace with the rapid
13 demand from employers. The talent pool is limited not in its total size, but in the availability of
14 candidates with the precise, sought-after expertise required to fill critical roles. Furthermore, the
15 intense competition for these specific skill sets among the region's employers means that even
16 a modest increase in the qualified population is quickly absorbed, leaving the talent pool feeling
17 consistently constrained.

18
19 c) The results of two recent recruitment related campaigns are described below:

20
21 An eight week social media campaign, created to promote Hydro Ottawa as a diverse and
22 sustainability-focused company where there are numerous career opportunities was relaunched
23 in early 2025. The goal of the campaign was to promote clicks to the careers portal and
24 applications for the open positions. This digital campaign targeted Ottawa and its surrounding
25 area within a 60 km radius.

26
27 The campaign resulted in 1.6 million impressions or total number of times the ads were
28 displayed on users' screens. This type of high level advertising creates general awareness of
29 Hydro Ottawa as an employer of choice and inherently drives an increase in applicants to our
30 organization. In addition, the campaign results indicated 27,724 total clicks to Hydro Ottawa's
31 career pages.

1 Further, Hydro Ottawa has refreshed its Employer Brand Strategy which includes aligned
2 messaging and visuals that accurately portray and promote the employee value proposition
3 (EVP) and entices potential candidates to consider a career at Hydro Ottawa.

4
5 Since early 2025 we have increased our presence on social media, targeting LinkedIn as it
6 aligns with messaging we seek to put out to potential employees. Messaging includes posts that
7 tell a compelling story focusing on showcasing our EVP and sharing informative and engaging
8 content. To date, efforts have resulted in over 78k impressions and close to 5,200 clicks, with an
9 average engagement rate of 7.46%. The engagement rate is a metric that reflects how well
10 content resonates with the intended audience by measuring the percentage of people who
11 interact with posts (like, share, etc) after seeing them. Hydro Ottawa also gained over 810 new
12 followers to the company's page, which demonstrates our efforts of creating engaging content is
13 increasing our brand awareness.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-169**

4
5 **EVIDENCE REFERENCE:**

6
7 Hybrid Work

8 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment B / p. 17 (pdf p. 162)

9
10 **QUESTION(S):**

- 11
12 a) What are Hydro Ottawa’s current hybrid work arrangements as a structured program? Please
13 explain.
14 b) Reference 1 states that the nature of Hydro Ottawa’s work requires its employees to be located
15 in or near Ottawa which can limit the size of the talent pool for some skill sets. Please provide a
16 percentage of FTEs (per year) that have to be located in or near Ottawa as part of the total
17 workforce from 2021 to 2026.

18
19 _____
20 **RESPONSE(S):**

- 21
22 a) Hydro Ottawa’s hybrid work model provides the opportunity for hybrid or work from home
23 options for eligible roles. Roles that would not be eligible for hybrid work would include those
24 where work is conducted in the field or can only be conducted at a Hydro Ottawa work
25 location/site, or work that must be physically conducted in the office to use or monitor
26 equipment, systems and/or operations.

27
28 The model stipulates two mandatory anchor days in the office - one corporate anchor day for all
29 employees and an additional anchor day determined by each divisional leadership team to
30 ensure opportunities to connect, engage and meet in person both as teams and
31 cross-divisionally/cross-functionally.

1 A maximum of 6 Working from Home (WFH) days over a 10-day period is allowed for eligible
2 roles. Determination of the number of in-office and WFH days is based on specific roles and
3 task/work. Those roles where greater collaboration, innovation, knowledge sharing and
4 engagement with other teams is expected, and those roles that provide direct support to
5 operational teams will have a greater number of in-office days. Decisions on the balance of
6 in-office and WFH days are made by divisional leadership teams. Further, employees must
7 adhere to Hydro Ottawa's Hybrid Work Protocol and consistently meet performance
8 expectations to be approved for hybrid/work from home options. The Hybrid Work Protocol
9 includes elements such as having a dedicated workspace where all roles and responsibilities
10 can be performed, within prescribed work hours, free from distractions, including having child
11 care arrangements in place, having internet capacity that fully and consistently supports work
12 and effective communication and workflow with customers, team members and supervisor and,
13 ensuring adherence to all Hydro Ottawa policies, procedure and practices.

14

15 b) 100% of FTEs have to be located in or near Ottawa as part of the total workforce from 2021 to
16 2026. As per our Hybrid Work Protocol, "Home" is defined as a location within 2 hours or less of
17 Ottawa, to ensure employees can be in the office in a reasonable amount of time should that be
18 required. Hydro Ottawa has obligations to restore power quickly which can mean that
19 office-based roles are deployed to other on-site functions to support restoration efforts.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-170**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment B / pp. 28-32 (pdf pp. 173-176)

8 Ref. 2: Exhibit 4 / HOL_Attachment 4-1-3(D) / Tab App.2-K_Employee Costs

9
10 **QUESTION(S):**

11
12 a) Table 3 in reference 1 shows that the annual external job postings increased significantly from
13 131 in 2021 to 247 in 2022 while reference 2 shows the total number of FTE increased by only
14 10 in 2022. Please explain why the significant increase in job postings in 2022 is not reflected in
15 the total number of FTEs in 2022.

16
17
18 **RESPONSE(S):**

19
20 a) As discussed in Attachment 4-1-3(B) - Workforce Planning Strategy on page 3, Hydro Ottawa
21 has kept its permanent positions relatively static for two successive rate periods. Recruitment
22 efforts within 2022 were primarily responding to vacancies that arose through employee attrition
23 and internal movements. Increases to the number of external postings in a given year are not
24 directly correlated to increases in FTEs. See Attachment 4-1-3(B) - Workforce Planning Strategy
25 on page 9-10 for information on Hydro Ottawa's elevated levels of attrition and internal
26 movements.

27
28 Further, not all recruitment efforts are successful in finding a candidate which may result in
29 multiple postings for a single vacancy. This is particularly true during periods with highly
30 competitive labour markets and/or for positions that require highly sought after skillsets.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

4-Staff-171

EVIDENCE REFERENCE:

Ref. 1: Exhibit 4 / Tab 1 / Schedule 3 / Attachment A / pp. 15-16 (pdf pp. 143-144)

Ref. 2: Exhibit 4 / HOL_Attachment 4-1-3(D) / Tab App.2-K_Employee Costs

Preamble:

Reference 1 states that the vacancy assumption is determined using historical and current trending which includes attrition (retirement and resignations), internal/external environmental factors and forecasting. The actual vacancy in 2022 and 2023 peaked at 12%. However, Hydro Ottawa states recent hiring efforts have been successful and the vacancy assumption is forecasted to continue to reduce. OEB staff notes that Table 10 in the reference shows the vacancy assumption of 10% for 2024 and 8% for 2025 and 2026.

In reference 1, Table 10 in reference 1 shows the 2024-2026 reconciliation of positions to FTEs in Appendix 2K (reference 2).

QUESTION(S):

- a) Please further explain or provide a spreadsheet (or a table) that support the derivation of the vacancy assumption numbers of 10% in 2024 and 8% in 2025 and 2026 based on historical and current trending which includes attrition (retirement and resignations), internal/external environmental factors and forecasting noted above.
- b) Please provide the vacancy rates forecast for the rest of the CIR period (2027-2030).
- c) From the vacancy rates in (b) and Table 10 in the reference, please update the table by adding 4 columns to include years 2027-2030 so that the total number of positions and FTEs add up to 177 and 100 respectively for this period.

1

2 **RESPONSE(S):**

3

4 a) Actual vacancy rates are calculated on both a quarterly and annual basis. The forecast takes
5 into account upcoming eligible retirements, attrition rate trending and current market demand for
6 specialized skill sets and/or experience. Also included in the forecast is the implementation and
7 effectiveness of programs aimed at enhancing recruitment efforts. As stated in Attachment
8 4-1-3(B) - Workforce Planning Strategy, Hydro Ottawa has implemented a number of programs
9 and initiatives to enhance external recruitment efforts and to increase awareness of career
10 opportunities at the utility. Please see response to 4-Staff-168 for details of the effectiveness of
11 recent recruitment activities.

12

13 In addition to the above, the external environment is also considered. Elements such as the
14 economic climate and its impact on the labour market, changes in prospective and current
15 employees attitudes toward employment arising post-pandemic, work from home, hybrid work
16 environment and work-life balance attitudes. While the vacancy rate was expected at 10% in
17 2024, increased hiring and the implementation of programs to attract and retain employees has
18 resulted in a lower forecast for 2025 and 2026. As at June 30, 2025, the vacancy rate is at 9%,
19 representing a drop of 2% from 2024's actual vacancy rate.

20

21 b) As shown in Table A below, the assumed vacancy rate for 2027-2030 is 6%.

22

23 c) Table A below is an updated version of Table 10 from Attachment 4-1-3(A) - Employee
24 Compensation Strategy that includes 2027-2030 as well as additional rows to show the new
25 positions by year adding up to 177 total and the additional 100 FTE in 2026 compared to the
26 2021 OEB Approved FTEs.

1 **Table A - 2024-2030 Reconciliation of Positions to FTEs in Appendix-2K¹**

Programs	Bridge		Test				
	2024	2025	2026	2027	2028	2029	2030
177 Positions added	50		81	37	6	1	2
Number of Full-Time Permanent Positions	667	667	748	785	791	792	794
Vacancy Assumption	10%	8%	8%	6%	6%	6%	6%
Vacancy Assumption translated into FTEs	(69)	(56)	(60)	(47)	(47)	(48)	(48)
Number of FTEs Sub total	598	611	688	738	744	744	746
Temps and Part Time	30	30	28	28	37	25	25
Number of FTEs (Appendix 2K)	628	641	716	766	780	769	771
2021 OEB Approved FTE			616				
FTE Growth from 2021			100				

2

¹ Totals may not sum due to rounding.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-172**

4
5 **EVIDENCE REFERENCE:**

6
7 Shared Services and Corporate Cost Allocation

8 Ref. 1: Exhibit 4 / Tab 2 / Schedule 1 / pp. 1-7 (pdf p. 277-283)

9 Ref. 2: Exhibit 1 / Tab 5 / Scheduled 1 / Attachment A / p. 4 (pdf p. 896)

10 Ref. 3: <https://oec.ca/news/oecandenvari>

11 Ref. 4: Affiliate Relationships Code (ARC) for Electricity Distributors and Transmitters (Revised
12 March 15, 2010) / Section 2.2.5, p. 8

13
14 Preamble:

15 Reference 1 states that Hydro Ottawa provides shared services to its affiliated companies: Hydro
16 Ottawa Holding Inc., Hydro Ottawa Energy Services Inc. and the other non-regulated entities within
17 Hydro Ottawa Capital Corporation. In addition, Hydro Ottawa provides shared corporate services to
18 Non-Regulated Activities in the same manner as affiliated Service Level Agreements (SLAs).

19
20 Reference 2 states that “Hydro Ottawa Holding Inc. (Hydro Ottawa) is a private company wholly
21 owned by the City of Ottawa. We own and operate four primary subsidiary companies: Hydro
22 Ottawa Limited (electricity distribution), Portage Power (renewable energy generation), Envari
23 (energy solutions) and Hiboo Networks (telecommunications services).”

24 Reference 3 states that Envari Holding Inc. (a subsidiary of Hydro Ottawa Holding Inc.) and OEC
25 announced their equal ownership of Tereflex Limited earlier in 2025.

26
27 **QUESTION(S):**

28
29 a) Have there been any changes to Hydro Ottawa’s shared service methodology since its last
30 rebasement application in 2021? If so, please explain and provide additional information of all
31 changes.

- 1 b) If not listed above, please provide additional names of all non-regulated entities that Hydro
2 Ottawa provides or receives shared corporate services to (if any).
- 3 c) Please confirm whether Hydro Ottawa has created new or updated any existing Service Level
4 Agreements (SLAs) for shared services with regards to the additional non-regulated entities
5 listed in question (b) above, and if so, whether such SLAs comply with transfer pricing
6 requirements under the ARC? Please provide the updated Procurement Policy (reference 2) to
7 include additional entitie(s).
- 8 d) Please explain the pricing methodology that Hydro Ottawa has with the new entities, including
9 how costs are allocated.
- 10 e) Please provide updated Appendix 2-N for 2024, 2025 and 2026.

11

12

13 **RESPONSE(S):**

14

15 a) No, there have not been any changes to Hydro Ottawa's shared service methodology since its
16 last rebasing application in 2021.

17

18 b) For the list of subsidiaries of Hydro Ottawa Capital Corporation, please see the response to
19 interrogatory CCC-12, part d).

20

21 c) Yes, Hydro Ottawa has updated existing or created new Service Level Agreements (SLAs) for
22 any affiliate to which it provides or from which it receives shared corporate services. These
23 SLAs comply with the transfer pricing requirements under the ARC.

24

25 Regarding the request to provide an updated Procurement Policy (Reference 2) to include
26 additional entities (Reference 2: Exhibit 1, Tab 5, Schedule 1, Attachment A, page 4 (pdf page
27 896)), Schedule 1-5-1 Attachment A refers to Hydro Ottawa Limited's audited financial
28 statements for the year ended 2023. The Procurement Policy and the accompanying Approval
29 Authority for Procurement and Disbursements Policy are included as Attachment 4-2-2 - (A) and
30 (B). Neither of these attachments has been updated since originally filed. It should be noted that
31 both documents apply to all entities and all employees of the corporate group, as defined in

- 1 Figure 1 of Schedule 1-6-1 - Corporate Structure and Governance. Lastly, page 896 of the
2 original submission pdf appears to be Attachment 1-5-2(A) – 2023 Hydro Ottawa Holding Inc.,
3 with page 4 (or pdf page 896) titled "Who we are." Similar to Figure 1 in Schedule 1-6-1,
4 Corporate Structure and Governance, this page lists the main subsidiaries.
5
- 6 d) Hydro Ottawa uses the same pricing methodology for all entities. Please refer to Table 1 of
7 Schedule 4-2-1 - Shared Services and Corporate Cost Allocation for a summary of the pricing
8 methodology for services provided by Hydro Ottawa to affiliates. Table 2 provides a summary of
9 the pricing methodology for services provided by Hydro Ottawa Holding Inc.
10
- 11 e) Please refer to the response to interrogatory 1-Staff-1 for updated Appendix 2-N for 2024
12 actuals. An updated 2025 forecast will not be available until October 2025. There are no
13 planned changes to the 2026 Test Year therefore no updates required to Appendix 2-N for 2025
14 and 2026.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-173**

4
5 **EVIDENCE REFERENCE:**

6
7 Shared Services and Corporate Cost Allocation

8 Ref. 1: Exhibit 4 / Tab 2 / Schedule 1 / p. 6 (pdf p. 282)

9 Ref. 2: Affiliate Relationships Code (ARC) for Electricity Distributors and Transmitters (Revised
10 March 15, 2010) / Section 2.2.5, p. 8

11
12 **QUESTION(S):**

13
14 a) The cost of shared corporate services received by Hydro Ottawa from Hydro Ottawa Holding
15 Inc. increased by almost \$1M in 2022 and by \$1.4M in 2023. Please provide the following:

16 i) Please explain in detail the main drivers of the increase including events that triggered
17 the demand for executive management time in 2022 and 2023.

18 ii) Reference 2 states that the transfer pricing rules set out in section 2.3 of the ARC do not
19 apply when a utility receives a service, resources, product or use of asset from an
20 affiliate in an emergency situation; a reasonable fully-allocated cost-related price shall be
21 determined afterwards by the parties. Please explain if there were any instances that the
22 cost-related price was determined differently during an emergency situation such as the
23 events that triggered the cost increase in a) i)? If yes, please explain in further detail.

24 b) Please explain in detail the changing regulatory landscape, energy security priorities, climate
25 change implications, and digital transformation that has necessitated an increase in other
26 services for the period 2021 to 2026 (reference 1). Please also explain what other services are
27 affected.

28 c) The costs in Table 4 (reference 1) show an increasing trend in shared corporate services
29 provided by Hydro Ottawa Holding Inc. from 2021 to 2026. Please explain how Hydro Ottawa
30 derived the estimated costs in 2024, 2025, and 2026.

1

2 **RESPONSE(S):**

3

4 a) i) As outlined in Section 4.1 of Schedule 4-2-1 - Shared Services and Corporate Cost
5 Allocation, the main drivers for the cost increase are the significant weather events that
6 occurred in 2022 and 2023, along with the 84-day-strike in 2023. These events triggered a
7 substantial demand for executive management time, which is a key component of the shared
8 corporate services received by Hydro Ottawa from Hydro Ottawa Holding Inc. Please also refer
9 to the response to interrogatory 4-Staff-156 for additional information.

10

11 ii) No, even for additional shared corporate services received from Hydro Ottawa Holding Inc.
12 relating to weather events and the labour strike, there were no instances where an emergency
13 pricing methodology was used. The cost increase was a result of increased time spent, but
14 there was no change to the pricing methodology for these emergency support services.

15

16 b) The changing regulatory landscape, evolving energy security priorities, climate change
17 implications, and the ongoing digital transformation of the industry have necessitated a greater
18 demand for executive management time and an increase in other corporate services. These
19 complex factors, which are often interrelated, require significant strategic capacity and
20 involvement at the executive level. The evolving regulatory environment, for instance, demands
21 that the company's executive management team actively assesses and responds to new OEB
22 initiatives and Ministry of Energy directives on electrification. Similarly, heightened awareness of
23 supply chain vulnerabilities and increased dependence on electricity have necessitated greater
24 planning, coordination, and resiliency efforts. More frequent and severe weather events require
25 rapid, coordinated responses from executive and operational leadership, which has reinforced
26 the need for long-term planning to improve system resilience. Lastly, as a critical infrastructure
27 operator, Hydro Ottawa has a heightened need for stronger cybersecurity and robust digital
28 infrastructure. This has necessitated direct engagement from executive leaders for new
29 technologies and enterprise-wide change management. These factors, in conjunction with
30 growth, have also necessitated an increase in corporate support across various functions,
31 including services such as Internal Audit, to ensure the company effectively manages these new

- 1 and complex risks. Please refer to the response to interrogatory 4-Staff-156 for additional
2 information.
- 3
- 4 c) Hydro Ottawa derived the estimated costs for 2024, 2025, and 2026 by applying the pricing
5 methodologies outlined in Table 2 of Schedule 4-2-1 - Shared Services and Corporate Cost
6 Allocation. The estimated costs were forecasted based on the budgets provided by each
7 functional group, which were then reviewed against historical averages, with one-time events
8 excluded. The proportional share of these costs was then allocated to each affiliate based on
9 management's knowledge of the business and the expected demand for services over the
10 forecast period.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-174**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 4 / Tab 2 / Schedule 3 / Table 1 / p. 1 (pdf p. 307)

8
9 **Preamble:**

10 Table 1 in the reference shows that a breakdown of regulatory costs (one-time) by category. OEB
11 staff notes that the total one-time regulatory cost related to the application has increased by \$3.1M
12 (133%) from \$2.3M in the 2021 OEB approved to \$5.4M in 2026.

13
14 In its last rebasing application, Hydro Ottawa states that only one Hydro Ottawa external expert
15 witness was engaged during the process, and Hydro Ottawa did not request incremental internal
16 staff costs. OEB staff notes that there is no expert witness cost in 2021 shown in Table 1.

17
18 **QUESTION(S):**

- 19
20 a) Please explain why there is no expert witness cost shown in the “Expert Witness Cost” line for
21 2021 in Table 1.
22 b) Please explain assumptions or provide calculations that Hydro Ottawa used to derive the
23 estimated one-time regulatory cost for each category for 2026. Please also explain why the
24 incremental internal staff costs have been included in regulatory costs in this Application when
25 the costs were excluded in the last rebasing application.

26
27
28 **RESPONSE(S):**

- 29
30 a) In Hydro Ottawa’s previous rebasing application, Hydro Ottawa had one expert witness
31 participate in the Technical conference, Clearspring Energy Advisors, specifically Steve Fenrick

1 witnessed the Total Cost Benchmarking as a result of its engagement in a Total Cost
2 Benchmarking study on the utility. For the input that was provided in Appendix 2-M, Hydro
3 Ottawa maintained the same presentment as was provided in the 2021-2025 rate application.
4 The costs related to Clearspring Energy Advisors, including the initial report and supporting all
5 steps of the application process are \$330K.

6
7 b) The estimated one-time regulatory cost for each category for 2026 was based on a combination
8 of work completed at that time, forecasting costs based on required studies and support prior to
9 submission, and estimates for additional consulting and expert witness support that would be
10 required throughout the rest of the proceeding. In addition, cost estimates for OEB hearing costs
11 and intervenor costs were based on past experience while looking at costs of other applications.
12 The estimates are based on management's judgement taking into account the increasing level
13 of complexity introduced into rate applications and assuming a full oral hearing, the potential for
14 some external witness involvement at later stages of the application and incremental internal
15 staff costs.

16
17 Incremental internal staff costs are based on the estimated compensation of staff hired
18 specifically for the preparation of this rate application or staff seconded to work on the rate
19 application whose substantive positions were backfilled, and an estimate of the overtime
20 required throughout the application process. Hydro Ottawa did not plan to hire as many
21 incremental internal temporary staff as it did, and did not budget for the overtime required when
22 estimating the 2021-2025 rate application costs; however, these costs were contemplated as
23 part of the 2026-2030 cost estimates. It was determined that supplementing application staffing
24 needs with new hires and backfilling seconded positions was necessary due to the project's
25 demands. The estimated incremental internal staff costs are not insignificant for this application,
26 therefore Hydro Ottawa included it in the one-time regulatory costs.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **4-Staff-175**

4
5 **EVIDENCE REFERENCE:**

6
7 **LEAP**

8 Ref 1: Exhibit 4 / Tab 2 / Schedule 5 / p. 1 (pdf p. 314)

9 Ref. 2: Filing Requirements, Chapter 2, December 9, 2024, Corrected May 7, 2025

10
11 **QUESTION(S):**

12
13 a) OEB staff was unable to verify Hydro Ottawa's calculated LEAP amount of \$324k in reference 1.
14 OEB staff calculated the LEAP amount for 2026 to be \$372k (0.12% x 2026 Service Revenue
15 Requirement amount of \$309,993,323). Please explain how Hydro Ottawa derived the LEAP
16 amount of \$324k for 2026.

17
18 **RESPONSE(S):**

19
20 a) Hydro Ottawa's 2026 LEAP contribution in Schedule 4-2-5 - Low-Income Energy Assistance
21 Program of \$324k was based on internal estimates computed prior to the completion of the
22 2026 Service Revenue Requirement for Hydro Ottawa's original application.

23
24 Hydro Ottawa agrees that per the filing of Attachment 6-1-1(A) - OEB Workform - 2026 Revenue
25 Requirement Workform on June 3, 2026, that the 2026 Service Revenue Requirement was
26 \$309,993,323 multiplied by 0.12% equals a LEAP contribution amount of \$372k in 2026. Hydro
27 Ottawa notes that this is a preliminary Service Revenue Requirement amount that could change
28 over the course of the rate application.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **5-Staff-176**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: EB-2024-0063 Cost of Capital Decision, March 27, 2025, p. 65

8 Ref. 2: Chapter 2 Appendices, 2-OA Capital Structure

9
10 **QUESTION(S):**

11
12 a) Please revise Appendices 2 - OA Capital Structure to show the Capitalization Ratio (% and \$),
13 Cost Rate (%), and Return (\$) of both Notional Long-term Debt and Actual Long-term Debt.
14 Please ensure the average of the Notional Long-term Debt and Actual Long-term Debt matches
15 that in the RRWF.

16
17
18 **RESPONSE(S):**

19
20 a) Hydro Ottawa notes that the 2025 Cost of Capital Decision and Order¹ states, with respect to
21 the calculation of notional debt, *“The OEB agrees with OEB staff’s submission. The rate for*
22 *notional debt will be at the lower of the DLTD at the time of issuance and the weighted*
23 *average cost of actual long-term debt, but only when there are material variances relating to the*
24 *notional debt (i.e., with material impacts on the revenue requirement).”*

25
26 Hydro Ottawa has provided the requested illustration in Attachment 5-Staff-176(A) - Appendix
27 2-OA showing Notional Long-term Debt, where the the weighted average cost of long-term debt
28 for 2026 has been applied to actual debt, and the weighted average cost of actual long-term
29 debt for 2025, being lower than the DLTD of 4.51%, has been applied to notional debt, both

¹ Ontario Energy Board, Decision and Order, Generic Proceeding - Cost of Capital and Other Matters ,
EB-2024-0063, (March 27, 2025), page 65

1 rates calculated in the updated Appendix 2-OB of Attachment 1-Staff-1(A) - Chapter 2
2 Appendices in the response to interrogatory 1-Staff-1.

3

4 The notional debt has no material impact on the revenue requirement as it is calculated using
5 the deemed capital structure. Additionally, Hydro Ottawa's borrowing costs have not been
6 adversely impacted by the existence of negative notional debt.

7

8 Hydro Ottawa was unable to match the average of the Notional Long-term Debt and Actual
9 Long-term Debt to the RRWF, as requested, however, Hydro Ottawa was able to match the sum
10 of the Notional Long-term Debt and Actual Long-term Debt to the RRWF, as shown in
11 Attachment 5-Staff-176(A) - Appendix 2-OA showing Notional Long-term Debt.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **5-Staff-177**

4
5 **EVIDENCE REFERENCE:**

6
7 **Short-Term Debt**

8 Ref. 1: Exhibit 5 / Tab 1 / Schedule 1 / p. 3 (pdf p. 3)

9
10 **Preamble:**

11 Hydro Ottawa Capital Corporation maintains short-term credit facilities and also has the ability to
12 issue commercial paper to support the liquidity needs of Hydro Ottawa.

13
14 **QUESTION(S):**

15
16 a) Please confirm Hydro Ottawa will apply the deemed OEB short-term debt rate, rather than the
17 actual short-term debt, when borrowing short-term funds from Hydro Ottawa Capital
18 Corporation.

19
20 **RESPONSE(S):**

21
22 a) Hydro Ottawa cannot confirm this statement. Please see Section 3.2 of Schedule 5-1-1 - Cost of
23 Capital and Capital Structure for an explanation of Hydro Ottawa's approach to short-term debt
24 funding which indicates that Hydro Ottawa receives the same terms that Hydro Ottawa Capital
25 Corporation receives through its credit facility. However, as described in Schedule 5-1-1 - Cost
26 of Capital and Capital Structure, the OEB's deemed short-term debt rate (DSTDR) and deemed
27 capital structure has been used to calculate the revenue requirement for 2026-2030.

28
29 In addition, Hydro Ottawa calculates the regulated return on equity (ROE) using the OEB's
30 DSTDR and deemed capital structure. Furthermore, the Earnings Sharing Mechanism (ESM)
31 calculations utilizes the OEB's deemed capital structure and the DSTDR.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **5-Staff-178**

4
5 **EVIDENCE REFERENCE:**

6
7 Long-Term Debt

8 Ref. 1: Exhibit 5 / Tab 1 / Schedule 1 / p.4 (pdf p. 4)

9
10 **QUESTION(S):**

11
12 a) As stated in reference 1, Hydro Ottawa Capital Corporation (HOCC) issues long-term debt to
13 support the financing requirements of Hydro Ottawa and the costs associated with the long-term
14 debt are passed on to Hydro Ottawa on the same terms and conditions as HOCC receives from
15 external markets. Please confirm if HOCC includes administration fees or related fees from
16 securing long-term debt for Hydro Ottawa. If yes, please provide details.

17
18
19 **RESPONSE(S):**

20
21 a) No, Hydro Ottawa Capital Corporation (HOCC) has not applied an administration fee in
22 connection with any of the promissory notes shown in Appendix 2-OB for the year 2026.

23
24 For clarity, HOCC has amortized \$2.4M of issuance costs paid to external third parties
25 (bookrunners, legal counsel, rating agency, auditor, etc.) over the term of the Series 2025-1
26 Senior Unsecured Debentures due 2035, which have an underlying rate of 4.372% plus 0.057%
27 for amortized issuance costs. This is reflected in the rate for the promissory notes issued on
28 February 3, 2025 and July 2, 2025 shown in Appendix 2-OB of Attachment 1-Staff-1(A) -
29 Chapter 2 Appendices in the response to interrogatory 1-Staff-1.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **5-Staff-179**

4
5 **EVIDENCE REFERENCE:**

6
7 Anticipated Long-Term Debt

8 Ref. 1: Exhibit 5 / Tab 1 / Schedule 1 / pp. 6-7 (pdf pp. 6-7)

9 Ref. 2: HOL _Attachment 5-1-1(B) - OEB Appendix 2-OB-Debt Instruments_20250415

10 Ref. 3: EB-2019-0261, Settlement Proposal, p. 25

11
12 **QUESTION(S):**

- 13
14 a) Please explain the methodology Hydro Ottawa has used to forecast the debt rates for the
15 upcoming debts in 2025 and 2026.
- 16 b) Please update Appendix-OA and Appendix-OB and attach the corresponding promissory notes
17 if there are any changes to the forecasted debt.
- 18 c) Hydro Ottawa is planning to secure additional debt in 2025-2026 as mentioned in reference 1,
19 primarily to fund its capital expenditure program and to repay maturing debt. Table 3 of
20 reference 1 shows a total debt amount of \$532M, whereas reference 2 shows the total amount
21 of \$478M. Please explain and reconcile the discrepancies.
- 22 d) In Reference 2, the table showing 2026 long-term debts indicates the most recent debt in 2026
23 will have a principal of \$55M, which does not align with Table 3 in Reference 1. Please
24 reconcile.
- 25 e) What due diligence has HOCC undertaken to ensure its preferred lender is offering a
26 competitive rate and product?
- 27 f) Has HOCC considered other financial institutions and channels aside from BMO Capital Market
28 to fund its short-term and long-term debt requirement? If not, please explain why.

1

2 **RESPONSE(S):**

3

4 a) Please refer to Schedule 5-1-1 - Cost of Capital and Capital Structure, pages 6-7, Section 3.4:
5 Anticipated Long-term Debt, for a detailed description of the methodology Hydro Ottawa has
6 used to forecast the rates for the upcoming debt issuances in 2025 and 2026. For clarity, the
7 rate reflected in the promissory notes issued on February 3, 2025 and July 2, 2025 are based
8 on the underlying annual coupon rate of Hydro Ottawa Capital Corporation's (HOCC) Series
9 2025-1 Senior Unsecured Debentures due 2035, 4.372% plus 0.057% for issuance costs.

10

11 b) Please refer to updated Appendix 2-OA and Appendix 2-OB of Attachment 1-Staff-1(A) -
12 Chapter 2 Appendices in the response to interrogatory 1-Staff-1. Please refer to attachment
13 5-CCC-63(A) - Hydro Ottawa Limited \$72.6M Promissory Note for a copy of the promissory note
14 issued by Hydro Ottawa to HOCC on July 2, 2025.

15

16 c) Please refer to updated Appendix 2-OB of Attachment 1-Staff-1(A) - Chapter 2 Appendices in
17 the response to interrogatory 1-Staff-1. As directed by the instructions in the Appendix 2-OB
18 template, Hydro Ottawa has separately calculated the pro-rated interest in the 2026 year and
19 inputted in the cell for the \$110M Grid Promissory Note forecast to be issued on July 2, 2026 at
20 the OEB's deemed long-term debt rate, given the financing is in place for only part of the year.

21

22 Please see the requested reconciliation between updated Appendix 2-OB of Attachment
23 1-Staff-1(A) - Chapter 2 Appendices in the response to interrogatory 1-Staff-1 and Table 3,
24 Recent and Forecast Long-Term Debt Issues in Schedule 5-1-1 - Cost of Capital and Capital
25 Structure below in Table A:

1 **Table A - Reconciliation between Table 3, Recent and Forecast Long-Term Debt Issues**
 2 **in Schedule 5-1-1 and updated Appendix 2-OB of Attachment 1-Staff-1(A) - Chapter 2**
 3 **Appendices in the response to interrogatory 1-Staff-1**

Description	Issue Date	Maturity Date	Outstanding Principal (\$)	Rate (%)
Promissory Note	03-Feb-2025	30-Jan-2035	\$350,000,000	4.429%
Promissory Note	02-Jul-2025	30-Jan-2035	\$72,600,000	4.429%
Grid Promissory Note	02-Jul-2026	Due of Demand	\$110,000,000	4.510%
Total as per Table 3 in Schedule 5-1-1 (Ref. 1)			\$532,600,000	
Adjustment for Grid Promissory Note financing in place for only part of the year (182 / 365 days * \$110,000,000)			(54,849,315)	
Total as per updated Appendix 2-OB of Attachment 1-Staff-1(A) - Chapter 2 Appendices (Ref. 2)			\$477,750,685	

4

5

6 d) Please refer to response c) above. Hydro Ottawa has separately calculated the pro-rated
 7 interest in the 2026 year and inputted in the cell for the \$110M Grid Promissory Note forecast to
 8 be issued on July 2, 2026, being $(183/365 \text{ days}) * \$110,000,000 = \$55,150,685$, as reflected in
 9 updated Appendix 2-OB of Attachment 1-Staff-1(A) - Chapter 2 Appendices in the response to
 10 interrogatory 1-Staff-1.

11

12 e) Please refer to Schedule 5-1-1 - Cost of Capital and Capital Structure, Section 3.2, Short-Term
 13 Debt, for an overview of Hydro Ottawa's short-term debt funding plan. HOCC is the borrower
 14 under a senior credit facility. HOCC has conducted due diligence to ensure its preferred lender
 15 is offering a competitive rate and product, by comparing the Term Canadian Overnight Repo
 16 Rate Average (CORRA) spread charged by its preferred lender, adjusted to facilitate
 17 comparison with the Spread over 90-day Bankers' Acceptance Rates reported by the OEB¹, and
 18 noted that the spread charged by HOCC's preferred lender is at the lower end of the range
 19 derived from a confidential survey of major Canadian banks for A (A-stable) commercial utility
 20 customers, and therefore continues to provide good value for Hydro Ottawa's ratepayers.

¹ Ontario Energy Board, Letter re: 2025 Cost of Capital Parameters (October 31, 2024).

1 Please refer to Schedule 5-1-1 - Cost of Capital and Capital Structure, Sections 3.3 and 3.4, for
2 an overview of Hydro Ottawa's long-term debt funding plan. HOCC's long-term debt rates are
3 set by an auction process whereby investors submit bids for a certain amount of the debt at a
4 specific interest rate, or yield, they are willing to accept, and the interest rate, or "coupon rate,"
5 for the debt is determined by the outcome of the auction. HOCC's most recent bond issuance, a
6 10-year 4.372% \$425 million offering completed on January 30, 2025, was >4.0x
7 oversubscribed, resulting in competitive pricing and thereby providing good value for Hydro
8 Ottawa's ratepayers.

9

10 f) Please refer to response e) above. HOCC is the borrower under a senior credit facility that is not
11 provided by BMO Capital Markets or Bank of Montreal.

12

13 HOCC's most recent bond issuance, also discussed in response e) above, was jointly led by
14 BMO Capital Markets and Scotia Capital, with the capital markets divisions of two other large
15 Canadian banks also participating in the syndicate. Please note that the agency fees charged
16 by bookrunners in the Canadian debt market are the same or similar across the various "big six"
17 Canadian banks.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **5-Staff-180**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: EB-2019-0261 / HOL_IRR_VECC_part 2 of 2_20200605 / VECC-92 / Figure A / p. 150

8
9 **QUESTION(S):**

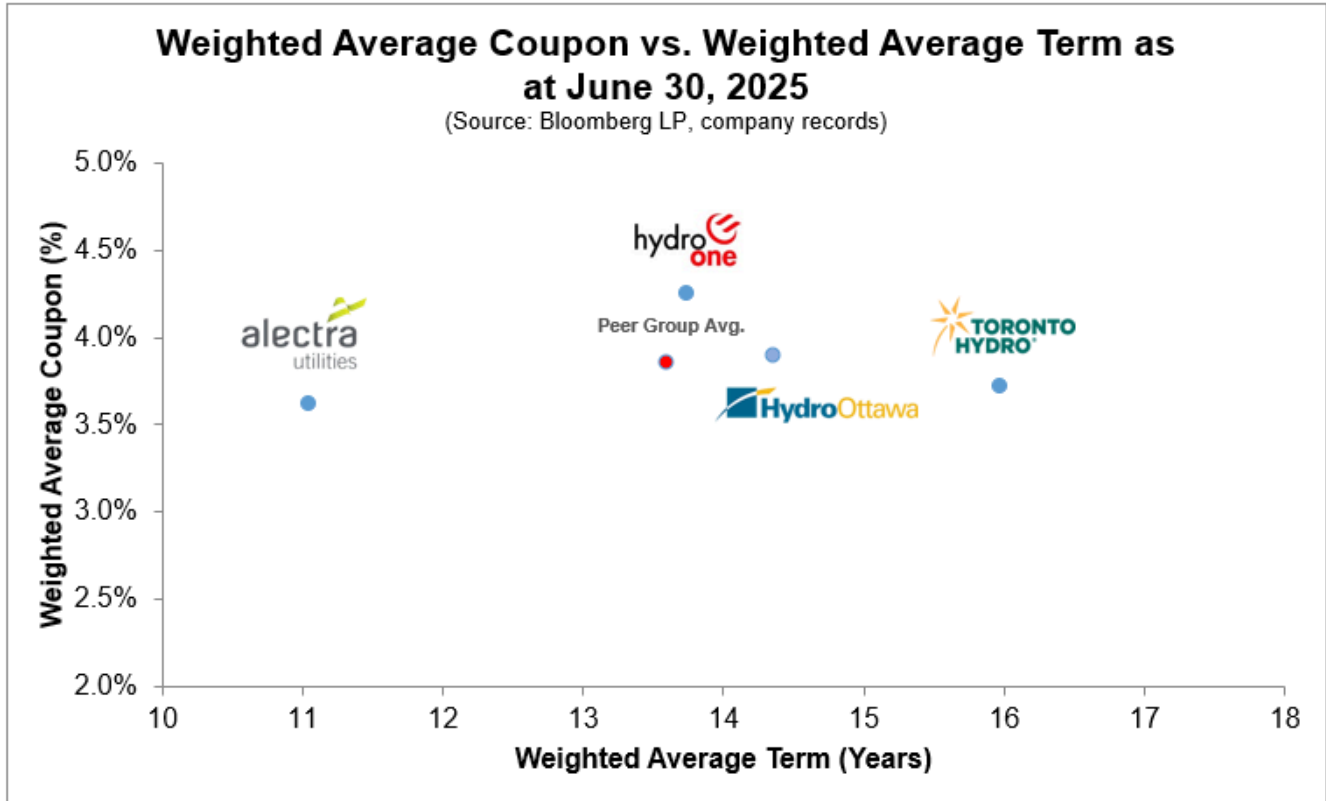
10
11 a) In Hydro Ottawa’s previous application (EB-2019-0261), Hydro Ottawa responded to a VECC IR
12 by providing a scatter plot showing the weighted average coupon vs weighted average term of
13 Hydro Ottawa compared to other peers to illustrate how Hydro Ottawa financing strategy is
14 beneficial to ratepayers. Please provide an updated copy if available.

15
16 _____
17 **RESPONSE(S):**

18
19 a) Please see the requested scatter plot below.

20
21 As shown in Figure A, Hydro Ottawa Capital Corporation’s weighted average coupon and
22 weighted average term remains competitive among its larger Ontario peers, and therefore
23 Hydro Ottawa’s financing strategy continues to benefit its ratepayers.

1 **Figure A – Weighted Average Coupon vs. Weighted Average Term as at June 30, 2025**



2

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **5-Staff-181**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 5 / Tab 1 / Schedule 1 / Table 4 / p. 8 (pdf p. 8)

8
9 **QUESTION(S):**

10
11 a) Please update Table 4 with the achieved ROE for 2024.

12
13 **RESPONSE(S):**

14
15 a) Please see the updated table below which presents the deemed and achieved regulated ROE
16 updated for 2024:

17
18 **Table A – Historical 2019-2024 Deemed and Achieved ROE**

Year	2019	2020	2021	2022	2023	2024
Deemed (included in Rates)	8.98%	8.98%	8.34%	8.34%	8.34%	9.21%
Achieved	8.82%	7.24%	8.49%	6.94%	6.15%	7.53%

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **5-Staff-182**

4
5 **EVIDENCE REFERENCE:**

6
7 Credit Rating Report

8 Ref. 1: Exhibit 1 / Tab 5 / Schedule 3 / Attachment A / p. 2 (pdf Exhibit 1 part 2 p. 1007)

9
10 **QUESTION(S):**

11
12 a) The Morningstar DBRS Rating Report stated that HOCC's unregulated business segments are
13 riskier compared to its regulated operation. However, these segments only represent a small
14 portion of HOCC earnings and do not materially affect HOCC's overall credit quality. Please
15 explain how HOCC ensures that there is no cross-subsidization between its unregulated and
16 regulated businesses.

17
18
19 **RESPONSE(S):**

20
21 a) Hydro Ottawa Capital Corporation (HOCC) ensures that there is no cross-subsidization between
22 its regulated and unregulated subsidiaries by ensuring that any loan, investment, or other
23 financial support provided to an unregulated subsidiary is provided on terms no more favourable
24 than what Hydro Ottawa receives from HOCC.

25
26 As referred to in the question above, the Morningstar DBRS Rating Report stated that HOCC's
27 unregulated business segments are riskier compared to its regulated operation, however, these
28 segments only represent a small portion of HOCC's earnings and do not materially affect
29 HOCC's overall credit quality. Therefore, Hydro Ottawa would not benefit from lower borrowing
30 costs were it to borrow directly from the capital markets rather than from HOCC.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-183**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 6 / Tab 2 / Schedule 1 / p. 11 (pdf p. 27), Table 7

8 Ref. 2: Exhibit 6 / Tab 2 / Schedule 1 / p. 12 (pdf p. 28), Table 8

9
10 **Preamble:**

11 In Reference 1, Hydro Ottawa provided a reconciliation of the Fixed Asset Continuity Schedule and
12 Schedule 8 Capital Additions in the PILs Workform for 2024 – 2030.

13
14 In Reference 2, Hydro Ottawa provided a reconciliation of the Fixed Asset Continuity Schedule and
15 PILs Workform amortization for 2023 – 2030. OEB staff notes that in Row 4, the non-rate-regulated
16 utility assets amortizations and non-rate base assets amortization/transfer are added back to the
17 Appendix 2-BA fixed asset depreciation in 2023 as part of the calculation to arrive at the
18 amortization reported in the PILs Workform.

19
20 **QUESTION(S):**

21
22 a) Please provide the reconciliation outlined in Reference 1 for 2023.

23 b) Please confirm the OEB staff's observation related to Table 8.

24 i) Please confirm if the amortization amounts reported in the PILs Workform for 2023 only
25 relate to rate base assets and rate-regulated utility assets.

26 ii) If not, please provide an explanation why the amortization related to non-rate base
27 assets and non-rate-regulated utility assets is reported in the PILs Workform.

1

2 **RESPONSE(S):**

3

4 a) Please see the interrogatory response in 1-Staff-1, specifically updated Table D and new Table
5 E.

6

7 b) i) The amortization amounts reported in the PILs Workform for 2023 includes both rate base
8 assets and rate regulated utility assets as well as non rate base and non rate-regulated utility
9 assets. The PILs Workform for 2023 requires the reconciliation to amounts in Hydro Ottawa's
10 2023 actual tax return. The actual tax return includes all assets (both rate base and non rate
11 base). As such, the PILs Workform for 2023, reconciles amortization for 2023 to Hydro Ottawa's
12 2023 tax return.

13

14 Hydro Ottawa has also updated the PILs Workform including the estimated 2024 Bridge Year to
15 Actuals. As such, the PILs Workform updated for the 2024 Historical is required to reconcile to
16 Hydro Ottawa's 2024 tax return. The PILs Workform can be found in the response to 1-Staff-1
17 as Attachment 6-2-1(E) - OEB Workform - 2026-2030 Income Tax/PILs Workform.

18

19 Hydro Ottawa can confirm that amortization for 2025 Bridge Year and 2026-2030 Test Years
20 only includes rate base assets and rate-regulated utility assets.

21

22 ii) The amortization in the PILs Workform only includes amortization for rate base assets and
23 rate regulated utility assets for 2025 Bridge Year and 2026-2030 Test Years. The amortization in
24 the Updated PILs Workform includes both rate base assets and non rate base assets and rate
25 regulated utility assets and non rate regulated assets for both 2023 Historical Year and 2024
26 Historical Year because both of these years have been reconciled to Hydro Ottawa's 2023 and
27 2024 tax returns as required by the PILs Workform. As Originally Submitted only the 2023
28 Historical Year included both rate base assets and non rate base assets and rate regulated
29 utility assets and non rate regulated assets.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-184**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(B)_Hydro Ottawa 2026-2030 PIL Tax Model_20250604 /
8 Tab H1

9 Ref. 2: Exhibit 6 / Tab 2 / Schedule 1 / Attachment A: 2023 Tax Return

10
11 Preamble:

12 In both References 1 and 2, Hydro Ottawa indicated that a tax loss of \$2,960,516 incurred in 2023
13 has been carried back to 2021 to reduce taxable income in that year.

14
15 Section 7.2.3 of the 2006 Electricity Distribution Rate Handbook (2006 EDR Report) states the
16 following.

17
18 A distributor expecting to have any loss carry-forwards still available on December 31, 2005
19 must disclose the amount of those loss carry-forwards in the 2006 application and apply
20 them in full to reduce the taxable income calculated in the 2006 regulatory tax calculation.

21 These amounts are to be entered in the 2006 OEB Tax Model.

22
23 **QUESTION(S):**

24
25 a) Please explain why Hydro Ottawa proposes to carry back the 2023 tax loss to the 2021 taxable
26 income instead of carrying it forward, as the guidance stated in the 2006 EDR Report. Please
27 provide any precedent cases where the losses were carried back.

28 b) Please provide an updated PILs Workform based on the scenario where the tax loss is carried
29 forward to the bridge and test years.

30 c) Please provide a copy of Hydro Ottawa's 2024 Tax Return.

1

2 **RESPONSE(S):**

3 a) The 2006 rates handbook¹ states in the Introduction to Section 7 Taxes / PILs that “The 2006
4 OEB Tax Model and its principles will only be applicable to the 2006 rate year. The Board has
5 not determined the process for the 2007 rate year, including whether or not the tax calculation
6 will be revisited for that rate year.”

7 In addition, the 2006 EDR Report does not specifically state that losses cannot be carried back.
8 The 2006 Report says that if there are losses available on December 31, 2005 that these losses
9 must be disclosed and applied to reduce regulatory taxable income for the 2006 PILs regulatory
10 tax calculation. If Hydro Ottawa applied the guidance in the 2006 EDR Report to the 2026 Test
11 Year, then Hydro Ottawa only needs to report that there are no expected carryforward losses at
12 December 31, 2025 to reduce taxable regulatory income for the 2026 PILS calculation. For the
13 updated PILS Workform, please see Attachment 1-Staff-1(E) - 2026-2030 Income Tax/PILS
14 Workform, where Hydro Ottawa has reported there are no expected carryforward losses at
15 December 31, 2025.

16 The *Accounting Procedures Handbook for Electricity Distributors*² (APH) outlines what tax
17 impacts should be captured in Account 1592 and considered for disposition between rebasing
18 applications. Please also see Schedule 9-1-4 - Account 1592 PILS and Tax Variance.

19 Corporate taxpayers are allowed to carry back non capital losses to the three prior years or to
20 carry forward non capital losses for 20 years. Prudent tax management would dictate that Hydro
21 Ottawa should carry-back losses to prior years if there is taxable income to utilize those losses
22 in any of the three prior years. Carrybacking the losses would result in a corporate taxpayer
23 receiving a refund of taxes paid in a prior year rather than waiting to carry forward the losses to
24 apply to a future tax year. While there will probably be taxable income in the future to absorb the
25 losses, there is more certainty in using those losses against taxable income of prior years. The
26 actual tax loss generated in 2023 was because of unforecasted and unexpected OM&A costs

¹ Ontario Energy Board, *2006 Electricity Distribution Rate Handbook* (May 11, 2005), page 57.

² Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors* (December 2011)

- 1 due to severe weather events, inflationary impacts on planned items, and an 84-day labour
2 strike. The loss carry forward does not fall within the requirements of Account 1592. In addition,
3 related to the rate period it is being used for. See Schedule 4-1-2 for further details about these
4 2023 events.
- 5
- 6 b) Hydro Ottawa has not provided the response as Hydro Ottawa believes it is aligned with the
7 policy related to 2006 PILs requirements. Prudent tax planning dictates that the 2023 taxable
8 loss be carried back to 2021 and not carried forward to the Test Years.
- 9
- 10 c) Please see Attachment 6-Staff-184(A) - Hydro Ottawas 2024 Tax Return (redacted).

Scientific Research and Experimental Development (SR&ED) Expenditures Claim

Use this form:

- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:

- Schedule T2SCH31, Investment Tax Credit – Corporations; or
- Form T2038(IND), Investment Tax Credit (Individuals).

The information requested in this form and documents supporting your expenditures and project information (Part 2) are prescribed information. In Part 6, a new box is added: Box 758 that must be filled if traditional method is used. The information is required for tax year ends after 2020 and optional for tax year ends before 2021.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, Guide to Form T661, which is available on our website: canada.ca/taxes-sred.

Part 1 – General information

<p>010 Name of claimant</p> <p style="text-align: center;">Hydro Ottawa Limited/Hydro Ottawa Limitee</p> <hr/> <p>Tax year</p> <p>From 2024-01-01 to 2024-12-31</p> <p style="font-size: small; text-align: center;">Year Month Day Year Month Day</p>	<p>Enter one of the following:</p> <div style="border: 1px solid black; padding: 5px; margin: 10px auto; width: 80%; text-align: center;"> [REDACTED] Business number (BN) </div> <div style="border: 1px solid black; padding: 5px; margin: 10px auto; width: 80%; text-align: center;"> [REDACTED] Social insurance number (SIN) </div>
<p>050 Total number of projects you are claiming this tax year:</p> <p style="text-align: center;">5</p>	
<p>100 Contact person for the financial information</p> <p style="text-align: center;">Bettina Yau</p>	<p>105 Telephone number/extension</p> <p style="text-align: center;">(613) 738-5499</p>
<p>115 Contact person for the technical information</p> <p style="text-align: center;">Bettina Yau</p>	<p>110 Fax number</p> <p style="text-align: center;"> </p>
	<p>120 Telephone number/extension</p> <p style="text-align: center;">(613) 738-5499</p>
	<p>125 Fax number</p> <p style="text-align: center;"> </p>

151 If this claim is filed for a partnership, was Form T5013 Partnership Information Return filed? Yes No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Names of the partners	156 %	157 BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060

Complete a separate Part 2 for each project claimed this year.

Code 1901

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year. I understand that my election is irrevocable (cannot be changed) for this tax year.

160 I elect to use the proxy method
(Enter "0" on line 360 and complete Part 5.)

162 I choose to use the traditional method
(Enter "0" on line 502. Complete line 360.)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:

a) Employees other than specified employees for work performed in Canada	300	+	2,329,394
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	2,329,394
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	

• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315	+	
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	3,823,132
b) Non-arm's length contracts	345	+	
• Overhead and other expenditures (enter "0" if you elected to use the proxy method at line 160)	360	+	
• Third-party payments (complete Form T1263*)	370	+	
Total allowable SR&ED expenditures (add lines 306 to 370; do not add line 315)	380	=	6,152,526

If the above expenditures have been included in your income statement, enter this amount on line 118 of Schedule T2SCH1 or, if you are an individual, include this amount in your self-employment income (lines 135 to 143) reported on your individual income tax and benefit return.

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

Amount from line 380	420		6,152,526
Deduct			
• provincial government assistance for expenditures included on line 380	429	–	188,466
• other government assistance for expenditures included on line 380	431	–	
• non-government assistance for expenditures included on line 380	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (do not include ITCs allocated from a partnership)	435	–	460,000
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	5,504,060
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	5,446,576
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	10,950,636
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	10,950,636
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, Third-Party Payments for Scientific Research and Experimental Development (SR&ED)

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes (to the nearest dollar)

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Total allowable SR&ED expenditures (from line 380)	492	<u>6,152,526</u>
Add		
• payment of prior years' unpaid amounts (other than salary or wages) (see note 1)	500 +	
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	<u>1,253,698</u>
• qualified expenditures transferred to you (see note 3) (complete Form T1146**)	508 +	
Subtotal (add lines 492 to 508)	511 =	<u>7,406,224</u>
Deduct		
• provincial government assistance	513 -	<u>232,346</u>
• other government assistance	515 -	
• non-government assistance and contract payments	517 -	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end (see note 1)	520 -	
• 80% of the amounts paid in respect of an SR&ED contract to a person or partnership that is not a taxable supplier	528 -	
• 20% of the amount on lines 340 and 370	529 -	<u>764,626</u>
• prescribed expenditures not allowed by regulations (see guide)	530 -	
• other deductions (see guide)	533 -	
• non-arm's length transactions		
– assistance allocated to you (complete Form T1145*)	538 -	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 -	
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 -	
– qualified expenditures you transferred (complete Form T1146**)	544 -	
Qualified SR&ED expenditures (line 511 minus lines 513 to 544)	559 =	<u>6,409,252</u>
Add		
• repayments of assistance and contract payments made in the year	560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)	570 =	<u>6,409,252</u>

* Form T1145, Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length

** Form T1146, Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length

Note 1 – For arm's length contracts, only include 80% of the contract amount.

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162). You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in Section B.

Section A – Salary base						
Salary or wages of employees other than specified employees (from lines 300 and 307)					810 +	2,329,394
Deduct						
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810					812 –	49,943
Subtotal (line 810 minus 812)					814 =	2,279,451
Salary or wages of specified employees						
850 Column 1	852 Column 2	854 Column 3	856 Column 4	858 Column 5	860 Column 6	
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less	
(Enter total of column 6 on line 816)					816 +	_____
Salary base (total of lines 814 and 816)					818 =	2,279,451

Section B – Prescribed proxy amount (PPA)	
Enter 55 % of the salary base (line 818)	820 = 1,253,698
Enter the amount from line 820 on to line 502 in Part 4 unless the overall cap on PPA applies to you. (See the guide for explanation and example of the overall cap on PPA)	

Part 6 – Project costs

Information requested in this part must be provided for all SR&ED projects claimed in the year. Expenditures should be recorded and allocated on a project basis.

* For Box 758, the information is required for tax year ends after 2020 and optional for tax year ends before 2021.

750	752	754	756	758
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)	Overhead and other expenditures in the tax year* (total of line 360, if applicable)
1 2023-01 Advancements in Grid Infrastructure Design	1,424,982		3,127,678	
2 2022-03 Integration Methods for Performant & Secure System	614,962		290,965	
3 2023-02 Data Mapping for Energy Usage	151,725		198,731	
4 2022-01 Advancements in Smart Grid Reliability	126,735		197,810	
5 2022-04 Advancements in System Integration Techniques	10,990		7,948	
Total	2,329,394		3,823,132	

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 380 minus lines 307, 309, 340, 345, and 370) **605** 2,329,394

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

	Canadian (%)	Foreign (%)
Internal 600	100.000	
Parent companies, subsidiaries, and affiliated companies 602		604
Federal grants (do not include funds or tax credits from SR&ED tax incentives) 606		
Federal contracts 608		
Provincial funding 610		
SR&ED contract work performed for other companies on their behalf 612		614
Other funding (e.g., universities, foreign governments) 616		618

For statistical purposes indicate whether the work you performed falls within the realm of Basic or Applied research (to advance scientific knowledge) or Experimental development (to achieve a technological advancement):

620 Basic or Applied research **622** Experimental development

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers 632	6
Technologists and technicians 634	14
Managers and administrators 636	
Other technical supporting staff 638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3
3. completed Part 2 for each project
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable

To expedite the processing of your claim, make sure you have:

1. completed Form T2, Corporation Income Tax Return or Form T1, Income Tax and Benefit Return
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable
3. retained documents to support the SR&ED work performed and SR&ED expenditures you claimed
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31

* Form T1145, Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length

** Form T1146, Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length

*** Form T1174, Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)

**** Form T1263, Third-Party Payments for Scientific Research and Experimental Development (SR&ED)

Part 9 – Claim preparer information

Information requested in this part must be provided for each claim preparer that has accepted consideration to prepare or assist in the preparation of this SR&ED claim. Certification is required on lines 935, 970, and 975.

A \$1,000 penalty may be assessed if the information requested below about the claim preparer(s) and billing arrangement(s), is missing, incomplete, or inaccurate. Where a claim preparer has prepared or assisted in the preparation of this SR&ED form, the claimant and the claim preparer will be jointly and severally, or solidarily, liable for the penalty.

935 Was a claim preparer engaged in any aspect of the preparation of this SR&ED claim?

- Yes (complete the claim preparer information table and lines 970 and 975 below)
- No (complete lines 970 and 975)

Claim preparer information table

940	945	950	955	960	965
Name of claim preparer (company or individual)	Business number	Billing arrangement code (see codes below*)	Billing rate (percentage, hourly/daily rate or flat fee)	Other billing arrangement(s) (Maximum 10 words)	Total fee paid, payable, or expected to pay
1. KPMG LLP	[REDACTED]	1	16.25		194,060
Total					194,060

*** Billing arrangement codes**

Code	Type of billing arrangement
1	Contingency fee arrangement – where the fee is based on a percentage of the investment tax credit earned
2	Hourly rate
3	Daily rate
4	Flat fee arrangement (lump sum)
5	Other arrangements – describe the arrangement in box 960 in 10 words or less

970 I, Geoff Simpson, certify that the information provided in this part is complete

Name of authorized signing officer of the corporation, or individual (print)

and accurate.

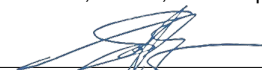

Signature

975 2025-06-19
Year Month Day

Part 10 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 Geoff Simpson
Name of authorized signing officer of the corporation, or individual


Signature

170 2025-06-19
Date

175
Name of person/firm who completed this form

Privacy Notice

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the Income Tax Act (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including assessment, audit, enforcement, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Refer to Personal Information Bank CRA PPU 441 in the Canada Revenue Agency (CRA) Information about Programs and Information Holdings – Personal Information Banks – Canada.ca. Under the Privacy Act, individuals have a right of access to, protection, and correction of their personal information and to file a complaint with the Privacy Commissioner of Canada regarding our handling of their personal information.

Part 2 – Project information (continued)

Project number 1

CRA internal form identifier 060

Code 1901

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)
2023-01 Advancements in Grid Infrastructure Design

202 Project start date 2021-09 Year Month	204 Completion or expected completion date 2025-07 Year Month	206 Field of science or technology code (See guide for list of codes) 2.02.01 Electrical and electronic engineering
--------------------------------------------------------	----------------------------------------------------------------------------	----------------------------------------------------------------------------------------------------------------------------------

Project claim history

208 Continuation of a previously claimed project **210** First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? Yes No

If you answered **yes** to line 218, complete lines 220 and 221.

220	Names of the businesses	221	BN
1			
2			
3			

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

- While the general concepts of grid such as reliability, adaptability,
- resilience, and sustainability are well-established, the industry is still
- contending with advanced zero-day cyber threats, climate change and so on.
- Integrating advanced monitoring systems, proactive failure detection
- algorithms, automated power quality control mechanisms, and system
- restoration capabilities into a cohesive and optimized grid management
- platform would require overcoming substantial technological uncertainties.
- [REDACTED]



242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

- 35. [REDACTED] To address this issue, HOL
- 36. sought to develop methods to ensure the newly created schematic layer closely
- 37. resembled the original diagrams while adhering to G/Technology standards.
- 38. Systematic investigations were necessary to determine if this will be
- 39. successful.

244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

- 1. [REDACTED]



244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

51. [Redacted]

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (Maximum 50 lines)

1. The work performed in FY2024 represented a technological advancement in the
2. field of electrical engineering.
3. Grid modernization was aimed at transforming the electric distribution system
4. into a more reliable, resilient, flexible, and intelligent grid that
5. effectively meets the evolving demands and expectations of customers. The
6. transition to Advanced Distribution Management System (ADMS) necessitated a
7. thorough gap analysis to identify inaccuracies in the existing "GIS" system.
8. [Redacted]

Section C – Additional project information

Who prepared the responses for Section B?

253	<input type="checkbox"/> Employee directly involved in the project	254 Name	
255	<input type="checkbox"/> Other employee of the company	256 Name	
257	<input checked="" type="checkbox"/> External consultant	258 Name KPMG LLP	259 Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260	Names	261	Qualifications/experience and position title
1	[REDACTED]		[REDACTED]
2	[REDACTED]		[REDACTED]
3	[REDACTED]		[REDACTED]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? Yes No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? Yes No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? Yes No

If you answered **yes** to line 267, complete lines 268 and 269.

268	Names of individuals or companies	269	BN
1	exp Services Inc.		[REDACTED]
2	Hatch Ltd.		[REDACTED]
3	Mindwire Systems Ltd.		[REDACTED]
4	Black & Veatch Canada Company		[REDACTED]
5	K2 Enterprise Security Inc.		[REDACTED]
6	Intergraph Canada Ltd.		[REDACTED]
7	Ice Dragon Corrosion Inc		[REDACTED]
8			

What evidence do you have to support your claim? (Check any that apply)

You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	<input type="checkbox"/> Project planning documents	276	<input checked="" type="checkbox"/> Progress reports, minutes of project meetings
271	<input checked="" type="checkbox"/> Records of resources allocated to the project, time sheets	277	<input checked="" type="checkbox"/> Test protocols, test data, analysis of test results, conclusions
272	<input type="checkbox"/> Design of experiments	278	<input type="checkbox"/> Photographs and videos
273	<input type="checkbox"/> Project records, laboratory notebooks	279	<input type="checkbox"/> Samples, prototypes, scrap or other artefacts
274	<input checked="" type="checkbox"/> Design, system architecture and source code	280	<input checked="" type="checkbox"/> Contracts
275	<input type="checkbox"/> Records of trial runs	281	<input type="checkbox"/> Others, specify 282

Part 2 – Project information (continued)

Project number 2

CRA internal form identifier 060
Code 1901

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2022-03 Integration Methods for Performant & Secure System

202 Project start date 2021-05 Year Month	204 Completion or expected completion date 2025-06 Year Month	206 Field of science or technology code (See guide for list of codes) 1.02.02 Information technology and bioinformatics (Software
--------------------------------------------------------	----------------------------------------------------------------------------	--------------------------------------------------------------------------------------------------------------------------------------------------

Project claim history

208 Continuation of a previously claimed project **210** First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? Yes No

If you answered **yes** to line 218, complete lines 220 and 221.

220	Names of the businesses	221	BN
1			
2			
3			

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

- Hydro Ottawa limited ("Hydro Ottawa" or "HOL") sought to develop a
- comprehensive security architecture for enhancing the security posture of
- substations in its network. This would allow for remote access to the
- substation security infrastructure for monitoring and troubleshooting cyber
- security issues.



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242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

[Redacted]

244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

1. Hydro Ottawa sought to implement a remote monitoring capability for network
2. traffic at substation sites to identify any potential cyber threats. A
3. proposed multi-tier security architecture was designed to facilitate nearly
4. real-time responses to identified cyber risks.

[Redacted]

20. [Redacted]

T661 E (

In

244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

- 51. FY24, HOL advanced its initiatives to fortify the protection of sensitive
- 52. information. Focused investigations were concentrated on assessing various
- 53. solutions capable of delivering real-time data protection across both
- 54. endpoint and cloud environments, particularly targeting risks of accidental
- 55. data leakage and malicious data theft.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (Maximum 50 lines)

- 1. The work performed in FY2024 represents a technological advancement in the
- 2. field of electrical IT systems.

4.

Section C – Additional project information

Who prepared the responses for Section B?

253	<input type="checkbox"/> Employee directly involved in the project	254 Name	
255	<input type="checkbox"/> Other employee of the company	256 Name	
257	<input checked="" type="checkbox"/> External consultant	258 Name KPMG LLP	259 Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260	Names	261	Qualifications/experience and position title
1	[REDACTED]		[REDACTED]
2	[REDACTED]		[REDACTED]
3			

265 Are you claiming any salary or wages for SR&ED performed outside Canada? Yes No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? Yes No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? Yes No

If you answered **yes** to line 267, complete lines 268 and 269.

268	Names of individuals or companies	269	BN
1	K2 Enterprise Security Inc.		[REDACTED]
2	Decisive Group Inc.		[REDACTED]
3	PricewaterhouseCoopers LLP		[REDACTED]
4			

What evidence do you have to support your claim? (Check any that apply)

You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	<input type="checkbox"/> Project planning documents	276	<input checked="" type="checkbox"/> Progress reports, minutes of project meetings
271	<input checked="" type="checkbox"/> Records of resources allocated to the project, time sheets	277	<input checked="" type="checkbox"/> Test protocols, test data, analysis of test results, conclusions
272	<input type="checkbox"/> Design of experiments	278	<input type="checkbox"/> Photographs and videos
273	<input type="checkbox"/> Project records, laboratory notebooks	279	<input type="checkbox"/> Samples, prototypes, scrap or other artefacts
274	<input checked="" type="checkbox"/> Design, system architecture and source code	280	<input checked="" type="checkbox"/> Contracts
275	<input type="checkbox"/> Records of trial runs	281	<input type="checkbox"/> Others, specify 282

Part 2 – Project information (continued)

Project number **3**

CRA internal form identifier 060
Code 1901

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)
2023-02 Data Mapping for Energy Usage

202 Project start date **204** Completion or expected completion date **206** Field of science or technology code
(See guide for list of codes)

2022-10 2025-06 1.02.02 Information technology and bioinformatics (Software
Year Month Year Month

Project claim history

208 Continuation of a previously claimed project **210** First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? Yes No

If you answered **yes** to line 218, complete lines 220 and 221.

220	Names of the businesses	221	BN
1			
2			
3			

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

- Hydro Ottawa Limited ("Hydro Ottawa" or "HOL") sought to develop techniques
- for moving its net-metering accounts to bill through the provincial system
- using CC&B as mandated by OEB (Ontario Energy Board). This was necessary to
- enable the net-metering users to select from a variety of billing rate
- options as provided by HOL, including Tiered, Ultra-low overnight (ULO) and
- TOU (Time of Use).

[Redacted content]

242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

35. [Redacted]

244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

1. The primary objective for HOL was to re-design its customer billing platform
2. for net-metering accounts, allowing them to opt for disparate billing rate
3. options.

[Redacted]

T661 E (

244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
[Redacted]

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (Maximum 50 lines)

1. The work performed in FY2024 represents a technological advancement in the
2. field of electrical IT systems. The project contributed to following
3. advancements:
4. HOL successfully developed techniques for enabling usage billing under new
5. billing rate categories for its net-metering customers. To realize this
6. design, methods were developed to effectively capture the smart meter data
7. records and seamlessly coordinate the data between various subsystems to
8. ensure data consistency for billing purposes. Additionally, a new credit
9. computation and disposal system was embedded into the billing process,
10. enabling HOL to issue applicable credit amounts in an automated and reliable
11. manner. The learnings as gained from this developed can be applied to any
12. future billing rate changes performed by HOL to its billing engine.
13. [Redacted]

Section C – Additional project information

Who prepared the responses for Section B?

253 <input type="checkbox"/> Employee directly involved in the project	254 Name	
255 <input type="checkbox"/> Other employee of the company	256 Name	
257 <input checked="" type="checkbox"/> External consultant	258 Name KPMG LLP	259 Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260	Names	261	Qualifications/experience and position title
1	[Redacted]		[Redacted]
2	[Redacted]		[Redacted]
3			

265 Are you claiming any salary or wages for SR&ED performed outside Canada? Yes No
266 Are you claiming expenditures for SR&ED carried out on behalf of another party? Yes No
267 Are you claiming expenditures for SR&ED performed by people other than your employees? Yes No

If you answered **yes** to line 267, complete lines 268 and 269.

268	Names of individuals or companies	269	BN
1	IBM Canada Ltd		[Redacted]

268 Names of individuals or companies	269 BN
2	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	<input type="checkbox"/>	Project planning documents	276	<input checked="" type="checkbox"/>	Progress reports, minutes of project meetings
271	<input checked="" type="checkbox"/>	Records of resources allocated to the project, time sheets	277	<input checked="" type="checkbox"/>	Test protocols, test data, analysis of test results, conclusions
272	<input type="checkbox"/>	Design of experiments	278	<input type="checkbox"/>	Photographs and videos
273	<input type="checkbox"/>	Project records, laboratory notebooks	279	<input type="checkbox"/>	Samples, prototypes, scrap or other artefacts
274	<input checked="" type="checkbox"/>	Design, system architecture and source code	280	<input checked="" type="checkbox"/>	Contracts
275	<input type="checkbox"/>	Records of trial runs	281	<input type="checkbox"/>	Others, specify 282

Part 2 – Project information (continued)

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2022-01 Advancements in Smart Grid Reliability

202 Project start date 2021-09 Year Month	204 Completion or expected completion date 2025-07 Year Month	206 Field of science or technology code (See guide for list of codes) 2.02.01 Electrical and electronic engineering
--------------------------------------------------------	----------------------------------------------------------------------------	------------------------------------------------------------------------------------------------------------------------------------

Project claim history

208 Continuation of a previously claimed project **210** First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? Yes No

If you answered **yes** to line 218, complete lines 220 and 221.

220	Names of the businesses	221	BN
1			
2			
3			

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

1. Hydro Ottawa Limited (HOL) continuously seeks to advance predictive
2. maintenance modeling of hydroelectric assets to improve the accuracy of
3. forecasting failures and mitigation strategies such that the life of assets
4. could be further extended. Traditionally, the underlying asset management
5. process in the industry hinges on consensus-based failure curves. On the
6. contrary, HOL hypothesised that a data-driven, evidence-based framework would
7. be more reliable and accurate. The key challenge was that the effectiveness
8. of data driven reliability engineering heavily depended on the quality and
9. comprehensiveness of the underlying data. The presence of "right censoring"
10. effect, where failure times for certain assets was not comprehensively
11. captured within the observation period could skew the forecasts, thus leading
12. to potentially inaccurate analysis. Additionally, any misalignment between
13. the timeframe for collecting operational data and the lifespan of previously
14. installed assets could result in extended periods of missing data. Such gaps
15. might contribute to increased left truncation effects, further complicating
16. the modeling efforts necessary for accurate reliability assessments.
17. Systematic investigations into data integrity were imperative for achieving
18. precise reliability engineering outcomes.

19. [Redacted]



242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

35. [Redacted]

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

1. [Redacted]

T661 E (

244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

[Redacted content]

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (Maximum 50 lines)

1. The work performed in FY2024 represented a technological advancement in the
2. field of electrical engineering.
3. The study conducted by Hydro Ottawa Limited (HOL) focused on improving asset
4. management practices through advancements in data-driven and evidence-based
5. methodologies.

[Redacted content]

Section C – Additional project information

Who prepared the responses for Section B?

253	<input type="checkbox"/> Employee directly involved in the project	254 Name	
255	<input type="checkbox"/> Other employee of the company	256 Name	
257	<input checked="" type="checkbox"/> External consultant	258 Name KPMG LLP	259 Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260	Names	261	Qualifications/experience and position title
1	[REDACTED]		[REDACTED]
2	[REDACTED]		[REDACTED]
3	[REDACTED]		[REDACTED]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? Yes No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? Yes No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? Yes No

If you answered **yes** to line 267, complete lines 268 and 269.

268	Names of individuals or companies	269	BN
1	Hatch Ltd.		[REDACTED]

What evidence do you have to support your claim? (Check any that apply)

You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	<input type="checkbox"/> Project planning documents	276	<input checked="" type="checkbox"/> Progress reports, minutes of project meetings
271	<input checked="" type="checkbox"/> Records of resources allocated to the project, time sheets	277	<input checked="" type="checkbox"/> Test protocols, test data, analysis of test results, conclusions
272	<input type="checkbox"/> Design of experiments	278	<input type="checkbox"/> Photographs and videos
273	<input type="checkbox"/> Project records, laboratory notebooks	279	<input type="checkbox"/> Samples, prototypes, scrap or other artefacts
274	<input checked="" type="checkbox"/> Design, system architecture and source code	280	<input checked="" type="checkbox"/> Contracts
275	<input type="checkbox"/> Records of trial runs	281	<input type="checkbox"/> Others, specify 282 _____

Part 2 – Project information (continued)

Project number **5**

CRA internal form identifier 060
Code 1901

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)
2022-04 Advancements in System Integration Techniques

202 Project start date 2021-05 Year Month	204 Completion or expected completion date 2025-06 Year Month	206 Field of science or technology code (See guide for list of codes) 1.02.02 Information technology and bioinformatics (Software
--------------------------------------------------------	----------------------------------------------------------------------------	--------------------------------------------------------------------------------------------------------------------------------------------------

Project claim history

208 Continuation of a previously claimed project **210** First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? Yes No

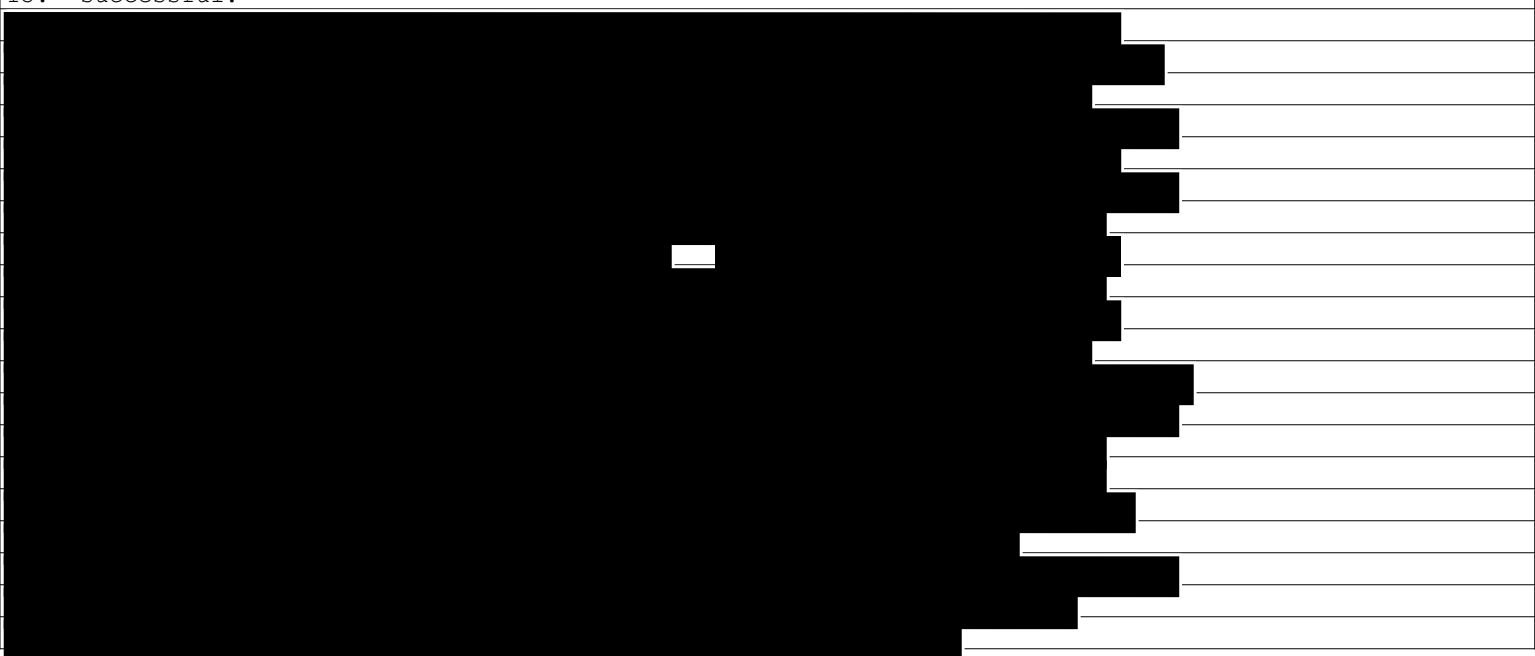
If you answered **yes** to line 218, complete lines 220 and 221.

220	Names of the businesses	221	BN
1			
2			
3			

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(Maximum 50 lines)

- Hydro Ottawa Limited (HOL or "the company") sought to develop an automated
- platform for seamlessly ingesting and processing meter data from both
- residential and commercial meters. This was required to generate metrics on
- the grid performance and running comparative tests. HOL currently utilizes a
- traditional approach for performing these actions with the different
- engineering and operations teams extracting the XML data and performing
- calculations in excel spreadsheets. This, however, proved to be time
- intensive and limited HOL's capacity in analyzing high volumes of data in a
- single instance. To address these issues, HOL proposed an automated data
- ingestion channel that pulled the data from the OEB (Ontario Energy Board)
- database in a synchronized manner and ran the disparate computations.
- Systematic investigations were required to determine if this could be
- successful.



244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

1. The primary aim of HOL was to construct an automated data pipeline to
2. efficiently integrate meter data into the data warehouse, facilitating
3. subsequent analytical processes. To achieve this, initial efforts were
4. directed towards thoroughly analyzing and mapping of the data gateway that
5. was supported by the OEB database. This step was crucial for comprehending
6. the intricate data structures and volume that required real-time processing
7. in order to yield meaningful grid-related insights.
- 8.

[REDACTED]



244 What work did you perform in the tax year to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (Maximum 100 lines)

58. [Redacted]

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (Maximum 50 lines)

1. The work performed in FY2024 represents a technological advancement in the
2. field of electrical IT systems. The project contributed to the following
3. advancements:
4. Hydro Ottawa was successful in developing an automated design for ingesting
5. and processing voluminous meter records, facilitating extensive analytical
6. capabilities. Moreover, through this approach, the team gained new knowledge
7. in enabling real-time data reporting through integration with a data
8. visualization solution. The learnings from this initiative could be applied
9. for efficiently managing data warehouses for multi-nodal data analysis.

10. [Redacted]

Section C – Additional project information

Who prepared the responses for Section B?

253	<input type="checkbox"/> Employee directly involved in the project	254 Name	
255	<input type="checkbox"/> Other employee of the company	256 Name	
257	<input checked="" type="checkbox"/> External consultant	258 Name KPMG LLP	259 Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260	Names	261	Qualifications/experience and position title
1	[REDACTED]		[REDACTED]
2	[REDACTED]		[REDACTED]
3			

265 Are you claiming any salary or wages for SR&ED performed outside Canada? Yes No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? Yes No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? Yes No

If you answered **yes** to line 267, complete lines 268 and 269.

268	Names of individuals or companies	269	BN
1	Nubik		[REDACTED]
2	Johnson Controls		[REDACTED]
3			

What evidence do you have to support your claim? (Check any that apply)

You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	<input type="checkbox"/> Project planning documents	276	<input checked="" type="checkbox"/> Progress reports, minutes of project meetings
271	<input checked="" type="checkbox"/> Records of resources allocated to the project, time sheets	277	<input checked="" type="checkbox"/> Test protocols, test data, analysis of test results, conclusions
272	<input type="checkbox"/> Design of experiments	278	<input type="checkbox"/> Photographs and videos
273	<input type="checkbox"/> Project records, laboratory notebooks	279	<input type="checkbox"/> Samples, prototypes, scrap or other artefacts
274	<input checked="" type="checkbox"/> Design, system architecture and source code	280	<input checked="" type="checkbox"/> Contracts
275	<input type="checkbox"/> Records of trial runs	281	<input type="checkbox"/> Others, specify 282

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2025-12-31

Business number XXXXXXXXXX

The following is a list of instalments payable for the current taxation year, and the last column indicates the instalments payable to the Canada Revenue Agency (CRA). The instalments must be paid on each of the dates indicated below, otherwise non-deductible interest might be charged.

You can pay using one of the methods listed at canada.ca/payments. However, when a remittance must mandatorily be made using electronic means, use one of the following electronic payment methods:

- a Canadian financial institution's services;
- the CRA's *My Payment* service, at canada.ca/cra-my-payment;
- a pre-authorized debit agreement set up in the CRA's *My Business Account* service, at canada.ca/my-cra-business-account;
- a wire transfer.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2025-01-31	58,455				58,455
2025-02-28	58,455				58,455
2025-03-31	88,765				88,765
2025-04-30	88,765				88,765
2025-05-31	88,765				88,765
2025-06-30	88,765				88,765
2025-07-31	88,765				88,765
2025-08-31	88,765				88,765
2025-09-30	88,765				88,765
2025-10-31	88,765				88,765
2025-11-30	88,765				88,765
2025-12-31	88,762				88,762
2026-01-31					89,650
2026-02-28					89,650
Totals	1,004,557				1,183,857

Quarterly instalment workchart

Date	Quarterly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2025-03-31					
2025-06-30					
2025-09-30					
2025-12-31					
2026-03-31					
Totals					

Instalment method

Indicate instalment method chosen [1-3] 2

Combined 1st and 2nd Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.).

1

Select this box if you want the instalments to be calculated without taking the applicable threshold into account

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

- 1 – Is the corporation a Canadian-controlled private corporation (CCPC)? Yes No
- 2 – Did the corporation claim any deduction under the section 125, during either the current or previous year? Yes No
- 3 – Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to \$500,000? Yes No
- 4 – Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to \$10,000,000? Yes No
- 5 – Does the corporation have a perfect compliance history in the last 12 months? Yes No

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments.

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	1,004,557 ÷ 12 =	83,714
	Monthly instalments required	83,714
Quarterly tax instalments required	1,004,557 ÷ 4 =	

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable threshold into account?

2nd Monthly instalment base amount

Indicate: Part I tax

Parts VI, VI.1 and XIII.1 tax	+		
Federal adjustment for amalgamation, winding up or transfer	+		
Provincial tax, other than Alberta, Québec and Ontario	+		
Ontario tax	+	772,695	
Provincial adjustment for amalgamation, winding up or transfer	+		
Total	=	772,695 ÷ 12 =	64,392 A
1/12 of estimated current year credits (M below /12)			- 5,937
		Each of the first two instalment payments	= 58,455 B
Total tax from N below		1,004,557	
Amount B above x 2	-	116,910	
	=	887,647 ÷ 10 =	88,765
		Each of the remaining ten instalment payments	= 88,765

2nd Quarterly instalment base amount

Indicate: Part I tax

Parts VI, VI.1 and XIII.1 tax	+		
Federal adjustment for amalgamation, winding up or transfer	+		
Provincial tax, other than Alberta, Québec and Ontario	+		
Ontario tax	+	772,695	
Provincial adjustment for amalgamation, winding up or transfer	+		
Total	=	772,695 ÷ 4 =	193,174 A
1/4 of estimated current year credits (M below /4)			- 17,810
		The first instalment payment	= B
Total tax from N below		1,004,557	
Amount B above	-		
	=	1,004,557 ÷ 3 =	334,853
		Each of the remaining three instalment payments	=

* It is the first payment if the quarterly instalments are applicable.

3 – Estimated tax method

Instalment base amount (amount N below)		÷ 12 =	
		Monthly instalments required	
Quarterly tax instalments required		÷ 4 =	

Instalment base calculation

Federal tax	1st instalment base method	Estimated tax method	
Taxable income	<u>2,108,802</u>		
Calculation of tax payable			
Federal part I tax	801,345		
Additional tax on personal services business income	+	+	
Additional tax on banks and life insurers	+	+	
Total labour requirements addition to tax	+	+	
Recapture of investment tax credit	+	+	
Refundable tax on a CCPC's investment income	+	+	
	<u>11,576</u>		
Subtotal	= 812,921	=	A
Deduction			
Small business deduction			
Investment corporation deduction	+	+	
Federal tax abatement	+	+	
	<u>210,880</u>		
Manufacturing and processing profits deductions	+	+	
Non-business foreign tax credit	+	+	
Business foreign tax credit	+	+	
General tax reduction	+	+	
	<u>260,036</u>		
Logging tax credit	+	+	
Investment tax credit per Schedule 31	+	+	
	<u>342,005</u>		
Eligible Canadian bank deduction	+	+	
Qualifying environmental trust tax credit	+	+	
Subtotal	= 812,921	=	B
Federal tax summary			
Total part I tax payable (A minus B)			C
Part VI tax	+	+	D
Part VI.1 tax	+	+	E1
Part XIII.1 tax	+	+	E2
Parts I, VI, VI.1 and XIII.1	Total	=	F
Federal adjustments			
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x <u>365 / 365</u>	x <u>365 / 365</u>	
Subtotal	=	=	
Federal adjustment for amalgamation, winding up or transfer	+	+	N/A
Total federal tax after adjustments	=	=	G
Provincial tax			
Provincial/territorial tax other than Alberta, Québec and Ontario before provincial refundable tax credits	+	+	H
Ontario tax			
Income tax			
Corporate minimum tax paid (credited)	+		
	<u>1,075,798</u>		
Special additional tax on life insurance corporations	+		
Total Ontario tax	= 1,075,798	+ 1,075,798	I
Harmonized provincial tax (H + I)			
Provincial/territorial tax other than Alberta and Québec before provincial refundable tax credits	= 1,075,798	=	J

Instalment base calculation (continued)

Provincial adjustments

Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365

	x	<u>365 / 365</u>	x	<u>365 / 365</u>	
Subtotal	=	<u>1,075,798</u>	=		
Provincial adjustment for amalgamation, winding up or transfer	+		+	<u>N/A</u>	
Total provincial tax after adjustments	=	<u>1,075,798</u>	=		K
Total of tax before refundable credits**	=	<u>1,075,798</u>	=		L

Estimated current year credits

Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
Tax withheld at source	+		+		
Canadian journalism labour tax credit	+		+		
Other estimated credits	+		+		
Provincial/territorial refundable tax credits other than Alberta, Québec and Ontario*	+		+		
Ontario refundable tax credits*	+	<u>71,241</u>	+		
Total estimated current year credits	=	<u>71,241</u>	=		M
Instalment base amount (L – M)		<u>1,004,557</u>			N

* For more details with regards to the impact of the refundable tax credits in the instalment base calculation, consult the Help.

** For instalments payable, the amount on line G will only be included in the amount of line L when it exceeds \$3,000. The same rule applies to line K.

T2 Corporation Income Tax Return

PILS FILING

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see canada.ca/taxes or Guide T4012, T2 Corporation – Income Tax Guide.

055 Do not use this area

Identification

Business number (BN) 001 [REDACTED]	
Corporation's name 002 Hydro Ottawa Limited/Hydro Ottawa Limitee	
Address of head office Has this address changed since the last time the CRA was notified? 010 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes , complete lines 011 to 018.	
011 _____	012 _____
015 City _____	016 Province, territory, or state _____
017 Country (other than Canada) _____	018 Postal or ZIP code _____
Mailing address (if different from head office address) Has this address changed since the last time the CRA was notified? 020 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes , complete lines 021 to 028.	
021 c/o _____	022 _____
023 _____	024 _____
025 City _____	026 Province, territory, or state _____
027 Country (other than Canada) _____	028 Postal or ZIP code _____
Location of books and records (if different from head office address) Has this address changed since the last time the CRA was notified? 030 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes , complete lines 031 to 038.	
031 _____	032 _____
035 City _____	036 Province, territory, or state _____
037 Country (other than Canada) _____	038 Postal or ZIP code _____
040 Type of corporation at the end of the tax year (tick one) <input checked="" type="checkbox"/> 1 Canadian-controlled private corporation (CCPC) <input type="checkbox"/> 2 Other private corporation <input type="checkbox"/> 3 Public corporation <input type="checkbox"/> 4 Corporation controlled by a public corporation <input type="checkbox"/> 5 Other corporation (specify) _____ If the type of corporation changed during the tax year, provide the effective date of the change 043 [REDACTED]	
To which tax year does this return apply? Tax year start 060 [REDACTED] Year Month Day 061 [REDACTED] Tax year-end Year Month Day 061 2024-01-01 061 2024-12-31	
Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? 063 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes , provide the date control was acquired 065 [REDACTED] Year Month Day	
Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? 066 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/>	
Is the corporation a professional corporation that is a member of a partnership? 067 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/>	
Is this the first year of filing after: Incorporation? 070 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> Amalgamation? 071 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes , complete lines 030 to 038 and attach Schedule 24.	
Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes , complete and attach Schedule 24.	
Is this the final tax year before amalgamation? 076 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/>	
Is this the final return up to dissolution? 078 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/>	
If an election was made under section 261, state the functional currency used 079 _____	
Is the corporation a resident of Canada? 080 Yes <input checked="" type="checkbox"/> No <input type="checkbox"/> If no , give the country of residence on line 081 and complete and attach Schedule 97.	
081 _____	
Is the non-resident corporation claiming an exemption under an income tax treaty? 082 Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes , complete and attach Schedule 91.	
If the corporation is exempt from tax under section 149, tick one of the following boxes: 085 <input type="checkbox"/> 1 Exempt under paragraph 149(1)(e) or (l) <input type="checkbox"/> 2 Exempt under paragraph 149(1)(j) <input type="checkbox"/> 4 Exempt under other paragraphs of section 149	
Do not use this area	
095	096
	898

Attachments

Financial statement information: Use GIFL schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

	Yes	Schedule
Is the corporation related to any other corporations?	<input checked="" type="checkbox"/>	9
Is the corporation an associated CCPC?	<input checked="" type="checkbox"/>	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	<input type="checkbox"/>	49
Does the corporation have any non-resident shareholders who own voting shares?	<input type="checkbox"/>	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	<input type="checkbox"/>	11
If you answered yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	<input type="checkbox"/>	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	<input type="checkbox"/>	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	<input checked="" type="checkbox"/>	15
Is the corporation claiming a loss or deduction from a tax shelter?	<input type="checkbox"/>	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	<input type="checkbox"/>	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	<input type="checkbox"/>	22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	<input type="checkbox"/>	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	<input checked="" type="checkbox"/>	29
Did the corporation have a total amount over CAN\$1 million of reportable transactions with non-arm's length non-residents?	<input type="checkbox"/>	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	<input checked="" type="checkbox"/>	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	<input type="checkbox"/>	
Does the corporation earn income from one or more Internet web pages or websites?	<input type="checkbox"/>	88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	<input checked="" type="checkbox"/>	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	<input checked="" type="checkbox"/>	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	<input checked="" type="checkbox"/>	3
Is the corporation claiming any type of losses?	<input type="checkbox"/>	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	<input checked="" type="checkbox"/>	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	<input checked="" type="checkbox"/>	6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or		
ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	<input checked="" type="checkbox"/>	7
Does the corporation have any property that is eligible for capital cost allowance?	<input checked="" type="checkbox"/>	8
Does the corporation have any resource-related deductions?	<input type="checkbox"/>	12
Is the corporation claiming deductible reserves?	<input checked="" type="checkbox"/>	13
Is the corporation claiming a patronage dividend deduction?	<input type="checkbox"/>	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	<input type="checkbox"/>	17
Is the corporation an investment corporation or a mutual fund corporation?	<input type="checkbox"/>	18
Is the corporation carrying on business in Canada as a non-resident corporation?	<input type="checkbox"/>	20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	<input type="checkbox"/>	21
Does the corporation have any Canadian manufacturing and processing tax profits or zero-emission technology manufacturing profits?	<input type="checkbox"/>	27
Is the corporation claiming an investment tax credit?	<input checked="" type="checkbox"/>	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	<input checked="" type="checkbox"/>	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over \$10,000,000?	<input checked="" type="checkbox"/>	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over \$10,000,000?	<input checked="" type="checkbox"/>	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	<input type="checkbox"/>	38
Is the corporation claiming a Part I tax credit?	<input type="checkbox"/>	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	<input type="checkbox"/>	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	<input type="checkbox"/>	45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	<input type="checkbox"/>	39
Is the corporation claiming a Canadian film or video production tax credit?	<input type="checkbox"/>	T1131
Is the corporation claiming a film or video production services tax credit?	<input type="checkbox"/>	T1177
Is the corporation claiming a Canadian journalism labour tax credit?	<input type="checkbox"/>	58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	<input type="checkbox"/>	92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271	<input type="checkbox"/>	T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN\$100,000?	259	<input type="checkbox"/>	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	<input type="checkbox"/>	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	<input type="checkbox"/>	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	<input type="checkbox"/>	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	<input type="checkbox"/>	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	<input type="checkbox"/>	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	<input checked="" type="checkbox"/>	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	<input type="checkbox"/>	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	<input type="checkbox"/>	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	<input checked="" type="checkbox"/>	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	<input type="checkbox"/>	54
Is the corporation claiming a return of fuel charge proceeds to farmers tax credit?	273	<input type="checkbox"/>	63
Are you an employer reporting a non-qualified security agreement under subsection 110(1.9)?	274	<input type="checkbox"/>	59
Is the corporation claiming an air quality improvement tax credit?	275	<input type="checkbox"/>	65
Is the corporation subject to the additional 1.5% tax on banks and life insurers?	276	<input type="checkbox"/>	68
Is the corporation a covered entity that redeemed, acquired or cancelled equity of the corporation in the tax year?	277	<input type="checkbox"/>	56
Is the corporation subject to the excessive interest and financing expenses limitation (EIFEL) rules contained primarily in sections 18.2 and 18.21, or is it a party to any election under the EIFEL rules?	278	<input checked="" type="checkbox"/>	130

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
Is the corporation inactive?	280	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Did the corporation meet the definition of substantive CCPC under subsection 248(1) at any time during the tax year?	290	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution					
Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.	284	DIST. OF ELECTRICITY		285	100.000 %
	286			287	%
	288			289	%
Did the corporation immigrate to Canada during the tax year?	291	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Did the corporation emigrate from Canada during the tax year?	292	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	Yes	<input type="checkbox"/>	No	<input type="checkbox"/>
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	Year Month Day			
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	Yes	<input type="checkbox"/>	No	<input type="checkbox"/>

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFL	300	2,246,058	A
Deduct:			
Charitable donations from Schedule 2	311	137,256	
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine made before March 22, 2017, from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction*	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Restricted interest and financing expenses from Schedule 4	336		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Employer deduction for non-qualified securities	352		
	Subtotal	137,256	
		137,256	B
	Subtotal (amount A minus amount B) (if negative, enter "0")	2,108,802	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C plus amount D)	360	2,108,802	

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7	400	2,137,534	A
Taxable income from line 360 on page 3, minus 100/28 (3.57143) of the amount on line 632* on page 8, minus 4 times the amount on line 636** on page 8, and minus any amount that, because of federal law, is exempt from Part I tax	405	2,108,802	B
Business limit (see notes 1 and 2 below)	410	500,000	C

- Notes:**
- For CCPCs that are not associated, enter \$ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
 - For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C 500,000 x **415** *** = 3,304,692 D = 90,000 E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** . **417** - 50,000 = .. F

Amount C 500,000 x Amount F 100,000 = .. G

The greater of amount E and amount G **422** 18,359,400 H

Reduced business limit (amount C **minus** amount H) (if negative, enter "0") **426** I

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) J

Reduced business limit after assignment (amount I **minus** amount J) **428** K

Small business deduction – Amount A, B, C, or K, whichever is the least x 19 % = **430**

Enter amount from line 430 at amount L on page 8.

- * Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.
- ** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** \$10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** \$10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

Small business deduction (continued)

Specified corporate income and assignment under subsection 125(3.2)

L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L ³	N Business limit assigned to corporation identified in column L ⁴
1.	490	500	505

Total **510** _____ Total **515** _____

Notes:

- This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
 - (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
 - (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
 - (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
 - (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
- The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula $A - B$, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Taxable income from line 360 on page 3		2,108,802	A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27			B
Amount 13K from Part 13 of Schedule 27			C
Personal services business income	432		D
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*			E
Aggregate investment income from line 440 on page 6**		108,524	F
Subtotal (add amounts B to F)		108,524	G
Amount A minus amount G (if negative, enter "0")		2,000,278	H
General tax reduction for Canadian-controlled private corporations – Amount H multiplied by 13 %		260,036	I

Enter amount I on line 638 on page 8.

* This is not applicable to substantive CCPCs.

** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, a substantive CCPC, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3			J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27			K
Amount 13K from Part 13 of Schedule 27			L
Personal services business income	434		M
Subtotal (add amounts K to M)			N
Amount J minus amount N (if negative, enter "0")			O
General tax reduction – Amount O multiplied by 13 %			P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Aggregate investment income from Schedule 7	440	108,524	x	30 2 / 3 %	=		33,281	A
Foreign non-business income tax credit from line 632 on page 8								B
Foreign investment income from Schedule 7	445		x	8 %	=			C
Subtotal (amount B minus amount C) (if negative, enter "0")								D
Amount A minus amount D (if negative, enter "0")							33,281	E
Taxable income from line 360 on page 3		2,108,802						F
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*								G
Foreign non-business income tax credit from line 632 on page 8			x	75 / 29	=			H
Foreign business income tax credit from line 636 on page 8			x	4	=			I
Subtotal (add amounts G to I)								J
Subtotal (amount F minus amount J)		2,108,802	K	x	30 2 / 3 %	=	646,699	L
Part I tax payable minus investment tax credit refund (line 700 minus line 780 from page 9)								M
Refundable portion of Part I tax – Amount E, L, or M, whichever is the least							450	N

* This is not applicable to substantive CCPCs.

Refundable dividend tax on hand

Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (line 530 of the preceding tax year)	520	A
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (line 545 of the preceding tax year) (if negative, enter "0")	535	B
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)	C	
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)	D	
Subtotal (amount C plus amount D)	▶	E
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525	F
ERDTOH dividend refund for the previous tax year	570	G
Refundable portion of Part I tax (from line 450 on page 6)		H
Part IV tax before deductions (amount 2A from Schedule 3)	I	
Part IV tax allocated to ERDTOH (amount E)	J	
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)	K	
Subtotal (amount I minus total of amounts J and K)	▶	L
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540	M
NERDTOH dividend refund for the previous tax year	575	N
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)		O
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount L minus amount O) (if negative enter "0")		P
NERDTOH at the end of the tax year (total of amounts B, H, M, and P minus amount N) (if negative, enter "0")	545	
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount E minus the amount, if any, by which amount O exceeds amount L) (if negative, enter "0")		Q
ERDTOH at the end of the tax year (total of amounts A, F, and Q minus amount G) (if negative, enter "0")	530	

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)	2,208,000	DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD minus amount EE (if negative, enter "0")	2,208,000	GG
Amount BB minus amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC plus amount FF plus amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) multiplied by 38 %	550	801,345	A
Additional tax on personal services business income (section 123.5)			
Taxable income from a personal services business	555	x 5 % = 560	B
Additional tax on banks and life insurers from Schedule 68	565		C
Total labour requirements addition to tax	580		D
Recapture of investment tax credit from Schedule 31	602		E
Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) or substantive CCPC's investment income (if it was a CCPC throughout the tax year or a substantive CCPC at any time in the tax year)			
Aggregate investment income from line 440 on page 6		108,524	F
Taxable income from line 360 on page 3	2,108,802		G
Deduct:			
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*			H
Net amount (amount G minus amount H)	2,108,802	2,108,802	I
Refundable tax on CCPC's or substantive CCPC's investment income – 10 2 / 3 % of whichever is less: amount F or amount I	604	11,576	J
Subtotal (add amounts A to E and J)		812,921	K
Deduct:			
Small business deduction from line 430 on page 4			L
Federal tax abatement	608	210,880	
Manufacturing and processing profits deduction and zero-emission technology manufacturing deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains	624		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount I on page 5	638	260,036	
General tax reduction from amount P on page 5	639		
Federal logging tax credit from Schedule 21	640		
Eligible Canadian bank deduction under section 125.21	641		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	342,005	
Subtotal		812,921	M
Part I tax payable – Amount K minus amount M			N
Enter amount N on line 700 on page 9.			

* This is not applicable to substantive CCPCs.

Privacy notice

Personal information (including the SIN) is collected and used to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be disclosed to other federal, provincial, territorial, aboriginal or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, and to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at canada.ca/cra-info-source.

Summary of tax and credits

Federal tax

Part I tax payable from amount N on page 8	700	
Part II.2 tax payable from Schedule 56	705	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part VI.2 tax payable from Schedule 67	725	
Part XII.7 tax payable from Schedule 78	726	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	

Add provincial or territorial tax:

Provincial or territorial jurisdiction	750	ON	
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)			
Net provincial or territorial tax payable (except Quebec and Alberta)	760		1,004,557

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount JJ on page 7	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Return of fuel charge proceeds to farmers tax credit from Schedule 63	795		
Canadian film or video production tax credit (Form T1131)	796		
Film or video production services tax credit (Form T1177)	797		
Canadian journalism labour tax credit from Schedule 58	798		
Air quality improvement tax credit from Schedule 65	799		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840		1,054,000
Total credits	890		1,054,000

Total federal tax _____
Total tax payable **770** 1,004,557 **A**

Balance (amount A minus amount B) -49,443 **B**

If the result is negative, you have a **refund**. If the result is positive, you have a **balance owing**.
Enter the amount below on whichever line applies.

Generally, the CRA does not charge or refund a difference of \$2 or less.

Refund code 894 <input type="text" value="1"/>	Refund <u>49,443</u>	Balance owing _____
-------------------------------------------------------	----------------------	---------------------

For information on how to enrol for direct deposit, go to canada.ca/cra-direct-deposit. For information on how to make your payment, go to canada.ca/payments.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** Yes No

If this return was prepared by a tax preparer for a fee, provide their: EFILE number **920** RepID **925**

Certification

I, **950** Simpson **951** Geoff **954** CFO

Last name First name Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2025-06-19 **956** (613) 738-5499
Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below **957** Yes No
958 Bettina Yau **959** (613) 738-5499
Name of other authorized person Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French. **990**
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

Schedule of Instalment Remittances

Name of corporation contact Bettina Yau
 Telephone number (613) 738-5499

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	INSTALLMENTS	1,054,000
Total amount of instalments claimed (carry the result to line 840 of the T2 Return)		<u><u>1,054,000</u></u> A
Total instalments credited to the taxation year per T9		<u><u>1,054,000</u></u> B

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIF1

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year end Year Month Day 2024-12-31
-----------------------------------------------------------------	-------------------------------	----------------------------------------------

Balance sheet information

Account	Description	GIFI	Current year	Prior year
Assets				
	Total current assets	1599 +	219,504,000	193,663,000
	Total tangible capital assets	2008 +	2,125,449,000	1,941,469,000
	Total accumulated amortization of tangible capital assets	2009 -	455,157,000	398,409,000
	Total intangible capital assets	2178 +	180,244,000	174,143,000
	Total accumulated amortization of intangible capital assets	2179 -	78,040,000	68,692,000
	Total long-term assets	2589 +	140,811,000	131,843,000
	* Assets held in trust	2590 +		
	Total assets (mandatory field)	2599 =	2,132,811,000	1,974,017,000
Liabilities				
	Total current liabilities	3139 +	607,115,000	261,193,000
	Total long-term liabilities	3450 +	1,028,189,000	1,246,711,000
	* Subordinated debt	3460 +		
	* Amounts held in trust	3470 +		
	Total liabilities (mandatory field)	3499 =	1,635,304,000	1,507,904,000
Shareholder equity				
	Total shareholder equity (mandatory field)	3620 +	497,507,000	466,113,000
	Total liabilities and shareholder equity	3640 =	2,132,811,000	1,974,017,000
Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849 =	330,426,000	299,032,000

* Generic item

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
-----------------------------------------------------------------	-------------------------------	----------------------------------------------

Income statement information

Description	GIFI
Operating name	0001
Description of the operation	0002
Sequence number	0003 01

Account	Description	GIFI	Current year	Prior year
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Income statement information

Total sales of goods and services	8089 +	1,236,070,000	1,117,944,000
Cost of sales	8518 -	940,048,000	878,410,000
Gross profit/loss	8519 =	296,022,000	239,534,000
Cost of sales	8518 +	940,048,000	878,410,000
Total operating expenses	9367 +	243,043,000	202,888,000
Total expenses (mandatory field)	9368 =	1,183,091,000	1,081,298,000
Total revenue (mandatory field)	8299 +	1,235,610,000	1,118,413,000
Total expenses (mandatory field)	9368 -	1,183,091,000	1,081,298,000
Net non-farming income	9369 =	52,519,000	37,115,000

Farming income statement information

Total farm revenue (mandatory field)	9659 +		
Total farm expenses (mandatory field)	9898 -		
Net farm income	9899 =		

Net income/loss before taxes and extraordinary items	9970 =	52,519,000	37,115,000
-------------------------------------------------------------	---------------	-------------------	-------------------

Total – other comprehensive income	9998 =		
-------------------------------------------	---------------	--	--

Extraordinary items and income (linked to Schedule 140)

Extraordinary item(s)	9975 -		
Legal settlements	9976 -		
Unrealized gains/losses	9980 +		
Unusual items	9985 -		
Current income taxes	9990 -	2,636,000	-257,000
Future (deferred) income tax provision	9995 -	12,729,000	8,574,000
Total – Other comprehensive income	9998 +		
Net income/loss after taxes and extraordinary items (mandatory field)	9999 =	37,154,000	28,798,000

General Index of Financial Information (GIFI) – Additional Information

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
-----------------------------------------------------------------	-------------------------------	----------------------------------------------

- Corporations need to complete all parts of this schedule that apply and include it with their T2 return along with their other GIFI schedules.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI), and Guide T4012, T2 Corporation – Income Tax Guide.

Part 1 – Information on the person primarily involved with the financial information

Can you identify the person* specified in the heading of Part 1? **111** Yes No

If you answered **no**, go to Part 2.

Does that person have a professional designation in accounting? **095** Yes No

Is that person connected** with the corporation? **097** Yes No

* A person primarily involved with the financial information is a person who has more than a 50% involvement in preparing the financial information that the T2 return is based on. For example, if three persons prepared the financial information by doing respectively 30%, 30%, and 40% of the work, answer **no** at line 111. If they did respectively 10%, 20%, and 70% of the work, answer **yes** at line 111 and complete Part 1 by referring only to the third person.

** A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement

Choose one or more of the following options that represent your involvement and that of the person referred to in Part 1:

Completed an auditor's report **300**

Completed a review engagement report **301**

Conducted a compilation engagement **302**

Provided accounting services **303**

Provided bookkeeping services **304**

Other (please specify) **305**

Part 3 – Reservations

If you selected option 1 (300) or 2 (301) in Part 2 above, answer the following question:

Has the person referred to in Part 1 expressed a reservation? **099** Yes No

Part 4 – Other information

Were notes to the financial statements prepared? **101** Yes No

Did the corporation have any subsequent events? **104** Yes No

Did the corporation re-evaluate its assets during the tax year? **105** Yes No

Did the corporation have any contingent liabilities during the tax year? **106** Yes No

Did the corporation have any commitments during the tax year? **107** Yes No

Does the corporation have investments in joint venture(s) or partnership(s)? **108** Yes No

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? **200** Yes No

If **yes**, enter the amount recognized:

	In net income Increase (decrease)	In OCI Increase (decrease)
Property, plant, and equipment	210	211
Intangible assets	215	216
Investment property	220	
Biological assets	225	
Financial instruments	230	231
Other	235	236

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? **250** Yes No

Did the corporation apply hedge accounting during the tax year? **255** Yes No

Did the corporation discontinue hedge accounting during the tax year? **260** Yes No

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? **265** Yes No

If **yes**, you have to maintain a separate reconciliation.

Part 5 – Information on the person who prepared the T2 return

If the person who prepared the T2 return has a professional designation in accounting but is not the person identified in Part 1, choose all of the following options that apply:

- Prepared the T2 return and the financial information contained therein **310**
- The client provided the financial statements **311**
- The client provided a trial balance **312**
- The client provided a general ledger **313**
- Other (please specify) **314** Prepared the T2 return

Corporation's name	Business number	Tax year end Year Month Day
Hydro Ottawa Limited/Hydro Ottawa Limitee		2024-12-31

General Index of Financial Information

Notes to the financial statements

1. DESCRIPTION OF BUSINESS AND CORPORATE INFORMATION

Hydro Ottawa Limited [the 'Company'] was incorporated on October 3, 2000 pursuant to the Business Corporations Act (Ontario) as mandated by the Ontario government's Electricity Act, 1998. On October 1, 2024, Hydro Ottawa Capital Corporation, a newly incorporated company, acquired the shares and assumed the unsecured promissory notes issued by the Company, from Hydro Ottawa Holding Inc., pursuant to the terms of a Purchase and Assumption of Liabilities Agreement. The Company is a wholly owned subsidiary of Hydro Ottawa Capital Corporation, which is in turn a wholly owned subsidiary of Hydro Ottawa Holding Inc. The Company's ultimate shareholder is the City of Ottawa. Prior to October 1, 2024, the Company was a directly wholly owned subsidiary of Hydro Ottawa Holding Inc., a wholly owned subsidiary of the City of Ottawa. The Company is domiciled in Canada with the registered head office located at 2711 Hunt Club Road, Ottawa, Ontario, K1G 5Z9.

Hydro Ottawa Limited is a regulated electricity distribution company that owns and operates electricity infrastructure in the City of Ottawa and the Municipality of Casselman and is responsible for the safe, reliable delivery of electricity to homes and businesses in its licensed service area. In addition to billing for distribution services, Hydro Ottawa Limited invoices customers for amounts it is required to pay to other organizations in Ontario's electricity system for providing wholesale generation and transmission services.

2. BASIS OF PRESENTATION

(a) Statement of compliance

These financial statements have been prepared by management on a going-concern basis in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ['IFRS Accounting Standards'], and have been approved and authorized by the Company's Board of Directors for issue on April 24, 2025.

(b) Basis of measurement

The Company's financial statements are prepared on a historical cost basis, except for employee future benefits as disclosed in Note 3(i)(ii).

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS Accounting Standards requires management to make estimates, judgments and assumptions that affect the reported amounts of revenues, expenses, assets, liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements.

Due to the inherent uncertainty involved in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the Ontario Energy Board ['OEB'] or the Ontario government. Management reviews its estimates and judgments on an ongoing basis using the most current information available. These financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the material accounting policies. Significant areas where estimates and judgments are made in the application of IFRS Accounting Standards are as follows:

i. Account receivables

Accounts receivable, which include unbilled receivables, are reported based on the amounts expected to be recovered less a loss allowance for expected credit losses. Management utilizes historical loss experience and forward-looking information in conjunction with the aging and arrears status

Corporation's name	Business number	Tax year end Year Month Day
Hydro Ottawa Limited/Hydro Ottawa Limitee		2024-12-31

General Index of Financial Information

Notes to the financial statements

of accounts receivable at year-end in the determination of the allowance.

ii. Regulatory balances

The recognition and measurement of regulatory balances is subject to certain estimates, judgments and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions. The Company continues to assess the likelihood of recovery of all regulatory debit balances subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation.

iii. Useful lives of depreciable assets

Depreciation and amortization expense are calculated based on estimates of the useful lives of property, plant and equipment, intangible assets and investment properties. Management estimates the useful lives of the various types of assets using assumptions and estimates of life characteristics of similar assets based on a long history of industry experience.

iv. Impairment of non-financial assets

Non-financial assets are reviewed by management for impairment using the future cash flows method. By their nature, estimates of future cash flows, including estimates of future capital expenditures, revenue, operating expenses, discount rates and market pricing are subject to measurement uncertainty.

v. Employee future benefits

The measurement of employee future benefits involves the use of numerous estimates and assumptions. Actuaries make assumptions for items such as discount rates, future salary increases and mortality rates in the determination of benefits expenses and defined benefit obligations.

vi. Capital contributions

The timing of the satisfaction of performance obligations for capital contributions from customers is subject to certain estimates of future electricity usage.

(e) New standard amendment adopted

In January 2020, the International Accounting Standards Board ['IASB'] issued amendments to International Accounting Standard Presentation of Financial Statements ['IAS 1'] relating to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria for classifying a liability as non-current is the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. This right may be subject to compliance with covenants.

After reconsidering certain aspects of the 2020 amendments, in October 2022, the IASB issued Non-current Liabilities with Covenants (Amendments to IAS 1), reconfirming that only covenants with which a company must comply on or before the reporting date affect a liability as current or non-current. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, with early adoption permitted. The amendments are applied retrospectively.

These amendments do not have any impact on the Company's financial statements and disclosures.

(f) New standard not yet adopted

In April 2024, the IASB issued a new standard, IFRS 18 Presentation and Disclosure of Financial Statements ['IFRS 18'], which replaces IAS 1. IFRS 18 is effective for reporting periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with early adoption permitted. IFRS 18 is expected to improve the quality of financial reporting by requiring defined subtotals in the statement of income or loss, requiring disclosure about management-defined performance measures, and adding new principles for aggregation and disaggregation of information.

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The Company has not yet determined the impact of this standard on its disclosures.

3. MATERIAL ACCOUNTING POLICIES

(a) Regulation

The Company is regulated by the OEB under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibilities of approving or setting rates for the transmission and distribution of electricity, and ensuring that distribution companies fulfill obligations to connect and service customers.

For fiscal year ended December 31, 2024, the Company continued to operate under a custom incentive rate-setting application ['Custom IR'] prescribed by the OEB. The Custom IR is one of the rate setting options contained in the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach policy.

Annual IR applications are required to set rates and charges for the 2022-2025 rate years. On August 15, 2024, the Company filed its Custom IR year 5 update application seeking approval to change its base distribution rates effective January 1, 2025. Rates are adjusted using a formulaic approach following the first year base rates. The 2025 rates are based on an update to the Company's custom price escalation factor, working capital allowance, and the Company's annual incremental capital stretch factor for capital-related revenue requirement. The Company's 2025 rates were approved by the OEB on December 17, 2024.

Once rates are approved, they are not adjusted as a result of actual costs being different from those that were estimated, other than for certain prescribed costs that are eligible for deferral treatment and are either collected or refunded in future rates.

In January 2014, the International Accounting Standards Board ['IASB'] issued IFRS 14 - Regulatory Deferral Accounts ['IFRS 14'], which permits rate-regulated entities to use its existing rate-regulated activities practices if and only if, in its first IFRS financial statements, it recognized regulatory deferral account balances by electing to apply the requirements of IFRS 14.

The Company has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the Accounting Procedures Handbook for Electricity Distributors. Regulatory debit and credit balances primarily represent costs that have been deferred because it is probable that they will be recovered in future rates, revenues that are required to be returned or collected to/from customers or balances that arise from differences in amounts billed to customers for electricity services and the costs that the Company incurs to purchase these services.

Regulatory balances principally comprise of the following:

- Regulatory asset/liability refund account ['RARA'/'RLRA'] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through temporary additional rates referred to as rate riders.
- Settlement variances relate primarily to the charges the Company incurred for transmission services, commodity, wholesale market operations and global adjustment in comparison to those settled with customers during the year. The nature of the settlement variances is such that the balance can fluctuate between assets and liabilities over time, and they are reported at year-end dates in accordance with rules prescribed by the OEB.
- Lost Revenue Adjustment Mechanism ['LRAM'] account tracks and disposes of lost electricity distribution revenues that result from Conservation and

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Demand Management ['CDM'] programs.

- Earnings Sharing Mechanism ['ESM'] variance account captures 50% of any regulated earnings above the Company's approved return on equity for specific rate periods.

- Other Post-employment Benefits deferral account ['OPEB deferral account'] was authorized by the OEB in 2011 to record the adjustment to employee future benefits other than pension relating to the cumulative actuarial gains or losses. This account is adjusted annually to record any changes in the cumulative actuarial gains or losses. No interest charges are recorded on this account as instructed by the OEB.

- Other Post-employment Benefits cash versus accrual account ['OPEB cash vs accrual'] tracks the interest on the differential of the Company's contributions to OPEB versus the accrued OPEB expense recorded in the Company's statement of income.

- Gain/Loss on Asset Disposal variance account is the difference between actual amount of gain or loss from disposal of fixed assets and the forecasted gain or loss.

Other variances and deferred costs include the following:

- The Connection Cost Recovery Agreement ['CCRA'] account allows the Company to record annual revenue requirements related to the difference between forecasted payments built into rates and actual payments made to Hydro One Networks Inc. ['HONI'] under the CCRA's.

- Capital Variance Account ['CVA'] account (excluding the System Access capital variance sub-account relating to plant relocation requested by third parties and residential expansion) is an asymmetrical variance account. Accordingly, the CVA tracks on an annual basis [for years 2021-2025], the cumulative revenue requirement difference resulting from the underspending in the Company's three capital spending categories: System Renewal/System Service, System Access, and General Plant. The System Access capital variance sub-account records the cumulative revenue requirement difference due to both overspending or underspending and is referred to as a symmetrical variance account.

- A Performance Outcomes Accountability Mechanism account to return up to \$200 annually for each under-achieved target during the 2021-2025 custom incentive rate-setting period. The five targets impacted by this mechanism account are identified in the Company's settlement agreement.

- The OEB established a variance account for electricity distributors to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment models.

The Company accrues interest on the regulatory balances as directed by the OEB.

The Company continues to assess the likelihood of recovery of all regulatory debit balances subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation. If the requirement for a provision becomes more likely than not, Hydro Ottawa will recognize the provision in operating costs for the year.

(b) Revenue recognition

Depending on whether certain criteria are met, the Company recognizes revenue from contracts with customers when it transfers control over a product or service to a customer either over time or at a point in time. For revenue from other sources, the Company recognizes revenue over time taking into consideration the facts and circumstances of the arrangement.

Revenue is measured at the consideration received or receivable, excluding sales taxes and other amounts collected on behalf of third parties in the following revenue arrangements.

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i. Power recovery

Power recovery revenue represents the flow-through of the cost of power to the consumer as purchased by the Company and is recognized over time as electricity is delivered to the customer, as measured by meter readings or usage estimates. Power recovery revenue is regulated by the OEB and includes charges to customers for the electricity commodity, the transmission of electricity and the administration of the wholesale electricity system. The Company has determined that it acts as a principal in this revenue arrangement and therefore has presented it on a gross basis.

ii. Distribution

The Company charges customers for the delivery of electricity, based on rates established by the OEB. The rates are intended to allow the Company to recover its prudently-incurred costs and earn a fair return on invested capital. Distribution revenue is recognized over time as electricity is delivered to the customer, as measured by meter readings or usage estimates.

iii. Other

Other revenue comprises revenue earned under contracts for service work related to distribution operations, pole attachment and duct rentals, capital contributions received from customers amortized to revenue, and other account-related charges such as account set-up and late payment fees. Revenue earned under contracts for service work related to distribution operations is recognized over time as the corresponding costs are recognized proportionately with the degree of completion of the services under contract. Losses on such contracts are fully recognized when they become evident. In certain situations, capital contributions are required from customers to finance additions to property, plant and equipment when the estimated revenue resulting from the addition to property, plant and equipment is less than the cost of providing the service or where special equipment is needed to supply the customers' specific requirements. Since the contributions will provide current and future customers with ongoing access to the supply of electricity, these contributions are classified as deferred revenue and amortized into revenue on a straight-line basis over time [the period a customer will receive services], which is typically equivalent to the rate used for the depreciation of the related property, plant and equipment [service life of the related assets]. All other revenues are recognized over time as services are rendered, except for revenue from certain account-related charges, which is recognized at a point in time.

Capital contributions received from developers to construct or acquire property, plant and equipment for the purpose of connecting future customers to the Company's distribution network are considered out of scope of IFRS 15 - Revenue from Contracts with Customers ['IFRS 15']. Capital contributions received from developers are recognized as deferred revenue and amortized into revenue from other sources at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

(c) Financing costs

Financing costs are calculated using the effective interest rate method and are recognized as an expense unless they are capitalized as part of the cost of a qualifying asset.

(d) Income taxes

The Company is considered to be a Municipal Electric Utility ['MEU'] and is required to make payments in lieu of corporate income taxes ['PILS'] as contained in the Electricity Act, 1998, as all of its share capital is indirectly owned by the City of Ottawa and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the City of Ottawa. The Electricity Act, 1998 provides that a MEU that is exempt from tax under the Income Tax Act (Canada) ['ITA'] and the Taxation Act,

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Ontario ['TAO'] is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TAO if it were not exempt from tax.

The Company follows the liability method for recording income taxes. Under the liability method, current income taxes payable is recorded based on taxable income. Deferred income taxes arising from temporary differences in the accounting and tax basis of assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

The Company recognizes regulatory balances for the amounts of future income taxes expected to be refunded to or recovered from customers in future electricity rates as prescribed by the OEB.

(e) Financial instruments

Financial instruments are initially measured at the fair value of the consideration given or received plus transaction costs that are directly attributable to the acquisition or issue of the financial instrument.

The Company's financial assets, upon initial recognition, are classified as amortized cost or fair value [whereby subsequent changes in fair value are recognized either through OCI ['FVOCI'] or through profit and loss ['FVTPL'] as unrealized market adjustments]. Financial assets are classified based on the Company's business model for managing such assets and the contractual terms of the related cash flows.

The Company's financial liabilities, upon initial recognition, are classified as amortized cost or FVTPL. A financial liability is classified as FVTPL if it is classified as held-for-trading, it is a derivative or it is designated as such on initial recognition.

The Company classifies and subsequently measures its financial instruments as follows:

- Cash and accounts receivable are financial assets classified and measured at amortized cost using the effective interest method, less any impairment if applicable.

- Working capital facility, accounts payable and accrued liabilities, customer deposits and notes payable are financial liabilities classified and measured at amortized cost using the effective interest rate method.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties.

The Company's own credit risk and the credit risk of the counterparty are taken into account in determining the fair value of financial assets and liabilities. Financial instruments are classified using a three level hierarchy. The levels reflect the inputs used to measure the fair values of financial assets and financial liabilities, and are as follows:

- Level 1: inputs are unadjusted quoted prices of identical instruments in active markets;

- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; and

- Level 3: inputs for the liabilities that are not based on observable market data [unobservable inputs].

All financial assets except for those classified as FVTPL or FVOCI are subject to review for impairment at least at each reporting date. Impairment losses, if material, are recognized in net income. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

The Company recognizes loss allowances for expected credit losses ['ECLs'] on financial assets measured at amortized cost. The Company measures loss

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allowances for electricity receivables, unbilled receivables and trade receivables via a simplified approach as permitted by IFRS 9 - Financial Instruments ['IFRS 9'], at an amount equal to lifetime ECLs.

When determining whether the credit risk of a financial asset has increased, the Company performs a quantitative and qualitative analysis based on the Company's historical experience and forward-looking information. The Company assumes that the credit risk on a financial asset has increased significantly if it is more than 30 days past due. The Company considers a financial asset to be in default when the borrower is unlikely to pay its credit obligations to the Company in full, without recourse by the Company to actions such as realizing security.

Loss allowances for financial assets measured at amortized cost are deducted from the gross carrying amount of the assets. The gross carrying amount of a financial asset is written off to the extent that there is no realistic prospect of recovery.

(f) Property, plant and equipment

Property, plant and equipment consist principally of electricity distribution infrastructure, buildings and fixtures, land, rolling stock, furniture and equipment, and assets under construction.

Property, plant and equipment are measured at cost less accumulated depreciation and accumulated impairment losses, if any. Self-constructed asset costs comprise all directly attributable expenditures to bring the asset into operation including labour, materials, employee benefits, transportation, contracted services and borrowing costs. Where parts of an item in property, plant and equipment are significant and have different estimated economic useful lives, they are accounted for as separate items [major components] of property, plant and equipment. Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers and developers. Assets that are acquired from customers and developers are measured at fair value. Contributions from customers and developers are treated as deferred revenue.

The cost of major inspections and maintenance is recognized in the carrying value of an asset provided that the Company will derive future economic benefits from the expenditure. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing, repairs, and maintenance are expensed as incurred.

Depreciation is recorded on a straight-line basis over the estimated service life of each component of property, plant and equipment. Emergency capital spare parts that are expected to be used for more than one year are considered to be assets under construction and are depreciated only once they are put into service.

Gains and losses on disposal of retired, sold or otherwise derecognized property, plant and equipment are recognized in income and are calculated as the difference between net proceeds from disposal and the carrying amount of the asset.

The estimated useful lives, residual values and depreciation methods are reviewed at each year-end with the effect of any changes in estimate being accounted for on a prospective basis.

Estimated service lives for property, plant and equipment classes are as follows:

Land and buildings

Land Indefinite

Buildings and fixtures 10 to 75 years

Electricity distribution infrastructure 10 to 60 years

Equipment and other

Furniture and equipment 5 to 40 years

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Rolling stock 7 to 15 years

Assets under construction and land are not subject to depreciation.

Borrowing costs are capitalized as a component of the cost of self-constructed property, plant and equipment assets that take a substantial period of time to get ready for their intended use. The capitalization rate is the Company's weighted average cost of borrowing.

(g) Intangible assets

Intangible assets include land rights, capital contributions, computer software and assets under development.

Intangible assets with finite lives are measured at cost less accumulated amortization and accumulated impairment losses, if any. Intangible assets are amortized on a straight-line basis over the estimated service lives of the related assets.

Intangible assets are derecognized on disposal or when no further future economic benefits are expected from their use. Gains or losses on disposal of intangible assets are recognized in income and are calculated as the difference between net proceeds from disposal and the carrying amount of the asset.

The estimated useful lives and amortization methods are reviewed at each year-end with the effect of any changes in estimate being accounted for on a prospective basis.

Estimated service lives for intangible assets with finite lives are as follows:

Land rights 50 years

Computer software 5 to 13 years

Capital contributions 45 years

Borrowing costs are capitalized as a component of cost of self-constructed intangible assets that take a substantial period of time to get ready for their intended use. The capitalization rate is the Company's weighted average cost of borrowing.

(h) Impairment of non-financial assets

At the end of each reporting period, or earlier if required, management uses its judgment to assess whether there is an indication that the carrying amount of a non-financial asset [or cash generating unit, 'CGU'] exceeds its recoverable amount. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. This assessment involves the consideration of whether any events or changes in circumstances could have affected the recoverability of the carrying amount of a non-financial asset or CGU.

Management considers various indicators including, but not limited to, adverse changes in the industry or economic conditions, changes in the degree or method of use of an asset, a lower than expected economic performance of an asset or a significant change in market returns or interest rates. If any indication exists, the Company estimates the asset's recoverable amount, which is the higher of an asset or CGU's fair value less costs of disposal and its value in use. If the carrying value of a non-financial asset materially exceeds its recoverable amount, the difference is immediately recognized as an impairment loss in profit or loss.

Intangible assets not yet available for use are tested for impairment [within their respective CGUs] at least annually, and whenever there is an indication that the asset may be impaired.

When determining the recoverable amount, the Company determines its value-in-use by discounting estimated future cash flows to their present value using a discount rate that reflects changes in the time value of money and the risks specific to the asset or the CGU. The discount rate estimated and used by management represents the weighted average cost of capital

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determined for the CGU being tested.

At the end of a reporting period, if there is any indication that an impairment loss recognized in a prior period no longer exists or has decreased, the loss is reversed up to its recoverable amount. The carrying amount following the reversal must not be higher than the carrying amount that would have prevailed [net of amortization] had the original impairment not been recognized in prior periods.

(i) Employee future benefits

i. Pension plans

The Company provides pension benefits for its employees through the Ontario Municipal Employees Retirement System ['OMERS'] Fund [the 'Fund']. OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a defined benefit pension plan, which is financed by equal contributions from participating employers and employees and by the investment earnings of the Fund.

Although the plan is a defined benefit plan, sufficient information is not available to the Company to account for it as such because it is not possible to attribute the fund assets and liabilities between the various employers who contribute to the Fund. As a result, the Company accounts for the plan as a defined contribution plan, and contributions payable as a result of employee service are expensed as incurred as part of operating costs. The Company shares in the actuarial risks of the other participating entities in the plan, and its future contributions may therefore be increased due to actuarial losses relating to the other participating entities. In addition, the Company's contributions could be increased if other entities withdraw from the plan.

ii. Other post-employment benefits

Other post-employment benefits provided by the Company include life insurance and a collectively bargained retirement grant. These plans provide benefits to certain employees when they are no longer providing active service.

Employee future benefits expense is recognized in the period during which the employees render services.

Employee future benefits are recorded on an accrual basis. The defined benefit obligation and current service costs are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Actuarial gains and losses resulting from experience different from that assumed or from changes in actuarial assumptions are recognized in OCI. However, for the Company, these amounts are reclassified to a regulatory debit balance as prescribed by the OEB.

iii. Employee benefits

The Company provides short-term employee benefits, such as: salaries, employment insurance, short-term compensated absences, health and dental care. These benefits are recognized as the related service is rendered and is measured on an undiscounted basis. Short-term employee benefits are recognized as an expense unless they qualify for capitalization as part of the cost of an item of materials and supplies, property, plant and equipment, intangible assets. A liability is recognized in respect of any unpaid short-term employee benefits for services rendered in the reporting period.

(j) Customer deposits

Customer deposits are cash collections from non-residential customers to guarantee the payment of future energy bills and fulfillment of construction obligations. Deposits from customers to guarantee the payment of energy bills includes related interest amounts owed to the customers. Deposits estimated

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to be refundable to customers within the next fiscal year are classified as current liabilities and included in accounts payable and accrued liabilities.

(k) Provisions and contingencies

The Company recognizes provisions when there is a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability.

The evaluation of the likelihood of the contingent events requires judgment by management as to the probability of exposure to potential loss. Actual results could differ from these estimates.

A contingent asset is not recognized in the financial statements. However, a contingent asset is disclosed where an inflow of economic benefits is probable.

4. ACCOUNTS RECEIVABLE

Receivables from contracts with customers

2024

\$

2023

\$

Electricity receivable	75,329	71,600		
Unbilled receivables related to electricity		96,073	86,259	
Independent Electricity System Operator ['IESO'] receivable			12,086	
14,065 Trade and other receivables	13,973	7,261		
Amounts due from related parties [Note 23]	18,405	11,308		
Less: loss allowance [Note 15(c)]	(5,103)	(4,141)		
	210,763	186,352		

5. REGULATORY BALANCES

Information about the Company's regulatory balances is as follows:

Remaining recovery/ reversal [years]

2023

\$ Balances arising in the

year

\$

Recovery/ reversal

\$

Other movements(1)

\$

2024

\$

Regulatory debit balances

RARA	1 - 5	8,941	2,120	(8,702)	(16)	2,343	
Settlement variances	1 - 5	36,126	9,576	-	(6,477)		
39,225 OPEB cash vs accrual	1 - 5	3,532	(160)	-	-	3,372	
Regulatory asset for deferred income taxes							

(2)

82,622

12,733

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-							
-							
95,355							
Other variances and deferred costs							
1 - 5							
622							
(106)							
-							
-							
516							
	131,843	24,163	(8,702)	(6,493)		140,811	
Regulatory credit balances							
RLRA 1 - 5	1,277	(10,799)	10,794	(16)		1,256	
Settlement variances 1 - 5	4,841	19,673	-	(6,477)			
18,037ESM 1 - 5	1,541	75	-	-		1,616	
Gain on asset disposal 1 - 5	1,093	287	-	-		1,380	
LRAM 1 - 5	3,056	1,238	-	-		4,294	
OPEB deferral account 1 - 5	63	38	-	-		101	
Other variances and deferred costs							
1 - 5							
3,088							
151							
-							
-							
3,239							
	14,959	10,663	10,794	(6,493)		29,923	
Remaining recovery/ reversal [years]							
2022							
\$ Balances arising in the							
year							
\$							
Recovery/ reversal							
\$							
Other movements(1)							
\$							
2023							
\$							
Regulatory debit balances							
RARA 1 - 5	687	7,378	949	(73)		8,941	
Settlement variances 1 - 5	36,724	10,279	-	(10,877)			
36,126OPEB cash vs accrual 1 - 5	3,218	314	-	-		3,532	
Loss on asset disposal 1 - 5	148	-	-	(148)		-	
Regulatory asset for deferred income taxes							
(2)							
74,238							
8,384							
-							
-							
82,622							
Other variances and deferred costs							
1 - 5							
1,498							
(814)							
-							
(62)							

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622							
	116,513	25,541	949	(11,160)	131,843		
Regulatory credit balances							
RLRA 1 - 5	1,148	1,794		(1,592)	(73)	1,277	
Settlement variances 1 - 5		17,033		(1,315)	-	(10,877)	
4,841ESM 1 - 5	1,467	74		-	-	1,541	
Gain on asset disposal 1 - 5				1,241	-	(148)	1,093
LRAM 1 - 5	105	2,951		-	3,056		
OPEB deferral account 1 - 5		30	33	-	-	63	
Other variances and deferred costs							
1 - 5							
	1,902						
	1,248						
	-						
	(62)						
	3,088						
	21,685	6,026	(1,592)	(11,160)	14,959		

(1) Other movements represent reclassifications of balances
(2) The balance is being reversed through timing differences in the recognition of deferred income tax assets [Note 3(d)]
Details and descriptions pertaining to the above regulatory debit and credit balances are disclosed in Note 3(a) of these financial statements.

6. PROPERTY, PLANT AND EQUIPMENT

Land, buildings and structures							
\$ Electricity distribution infrastructure							
\$							
Equipment and other							
\$							
Assets under construction							
\$							
Total							
\$							
Cost							
Balance as at December 31, 2022			157,739	1,500,790	60,870		
76,019 1,795,418							
Additions, net of transfers		3,253	113,490	7,085	23,776		
147,604 Disposals (14)		(1,427)	(591)	-	(2,032)		
Balance as at December 31, 2023			160,978	1,612,853	67,364		
99,795 1,940,990							
Additions, net of transfers		11,292	141,559	8,054	26,659		
187,564 Disposals (149)		(2,748)	(650)	-	(3,547)		
Balance as at December 31, 2024			172,121	1,751,664	74,768		
126,454 2,125,007							
Accumulated depreciation							
Balance as at December 31, 2022			(19,408)	(293,545)	(31,306)	-	
(344,259)							
Depreciation (3,567)		(46,002)	(5,835)	-	(55,404)		
Disposals - 726		528	-	1,254			
Balance as at December 31, 2023			(22,975)	(338,821)	(36,613)	-	
(398,409)							
Depreciation (3,844)		(48,832)	(6,139)	-	(58,815)		
Disposals 36 1,445		586	-	2,067			
Balance as at December 31, 2024			(26,783)	(386,208)	(42,166)	-	
(455,157)							
Net book value							
As at December 31, 2023		138,003	1,274,032	30,751	99,795		
1,542,581							
As at December 31, 2024		145,338	1,365,456	32,602	126,454		

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1,669,850

During the year, the Company capitalized borrowing costs of \$836 [2023 - \$510] to property, plant and equipment. The average annual interest rate for 2024 was 3.6% [2023 - 3.4%].

The Company has entered into non-cash transactions that have been excluded from the statement of cash flows as detailed in Note 20. In addition, \$10,528 [2023 - \$12,105] of property, plant and equipment was contributed by developers, the directly related liability of which is included in deferred revenue.

During the year, the Company recognized a loss on disposal of property, plant and equipment of \$460 [2023 - gain on disposal of \$469].

7. INTANGIBLE ASSETS

Land rights

\$ Computer software
\$ Capital contributions
\$ Assets under development
\$

Total

\$

Cost

Balance as at December 31, 2022	3,239	79,766	83,893	3,456	
170,354					
Additions, net of transfers	-	6,265	(4,756)	2,280	3,789
Balance as at December 31, 2023	3,239	86,031	79,137	5,736	
174,143					
Additions, net of transfers	-	5,907	577	(383)	6,101
Balance as at December 31, 2024	3,239	91,938	79,714	5,353	
180,244					
Accumulated amortization					
Balance as at December 31, 2022	(546)	(53,645)	(5,855)	-	
(60,046)					
Amortization (78)	(6,622)	(1,946)	-	(8,646)	
Balance as at December 31, 2023	(624)	(60,267)	(7,801)	-	
(68,692)					
Amortization (78)	(7,385)	(1,885)	-	(9,348)	
Balance as at December 31, 2024	(702)	(67,652)	(9,686)	-	
(78,040)					
Net book value					
As at December 31, 2023	2,615	25,764	71,336	5,736	105,451
As at December 31, 2024	2,537	24,286	70,028	5,353	102,204

The Company is party to various Connection and Cost Recovery Agreements ['Capital contributions'] with Hydro One Networks Inc. ['HONI']. These agreements govern the construction by HONI of new or modified transformer stations for the purpose of serving the Company's customers, including anticipated electricity load growth. All terms and conditions of CCRAs follow the Transmission System Code [the 'Code'] issued by the OEB.

During the year, the Company capitalized borrowing costs of \$129 [2023 - \$184] to intangible assets. The average annual interest rate for 2024 was 3.6% [2023 - 3.4%].

The Company has entered into non-cash transactions that have been excluded from the statement of cash flows as detailed in Note 20.

8. WORKING CAPITAL FACILITY

The Company has access to a \$90,000 [2023 - \$90,000] revolving demand credit facility and a \$500 [2023 - \$500] commercial card facility available from its immediate parent, Hydro Ottawa Capital Corporation [prior to October 1, 2024 - Hydro Ottawa Holding Inc.]. As at December 31, 2024, the Company had drawn \$14,894 [2023 - \$10,310] in bank indebtedness and \$25,000 [2023 - \$55,000] in CORRA ['Canadian Overnight Repo Rate Average'] loans [prior to

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July 1, 2024 -- bankers' acceptances] against this credit facility. The rate of interest is based on the rate applicable to its immediate parent's outstanding CORRA loans drawn on that date. Otherwise, the rate of interest is based on the CanDeal/TMX Term CORRA 1 month rate, plus a CORRA loan spread.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

2024			
\$	2023		
\$			
Purchased power payable	66,951	87,382	
Trade accounts payable and accrued liabilities		49,280	35,271
Customer deposits	63,034	43,274	
Customer credit balances	14,541	14,451	
Due to related parties [Note 23]	8,483	7,106	
	202,289	187,484	

10. DEFERRED REVENUE

2024			
\$	2023		
\$			
Capital contributions from customers	154,780	138,249	
Capital contributions from developers	182,685	151,884	
	337,465	290,133	
Less: current portion	(10,266)	(8,399)	
	327,199	281,734	

11. EMPLOYEE FUTURE BENEFITS

(a) Pension plans

The Company's participating employer contributions under OMERS for the year ended December 31, 2024 amounted to \$6,621 [2023 - \$5,340].

(a) Other post-employment benefits

Employee future benefits are calculated using an annual compensation rate increase of 2.0% [2023 - 2.0%] and a discount rate of 4.7% [2023 - 4.7%] to calculate the liabilities. The valuations also include several other economic and demographic assumptions including mortality rates. The mortality assumption is based on the Canadian Pensioners' Mortality report published by the Canadian Institute of Actuaries in February 2014.

Information about the Company's other post-employment benefits is as follows:

2024			
2023			
\$	\$		
Defined benefit obligation, beginning of year	11,875	11,526	
Current service costs	298	265	
Interest on defined benefit obligation	546	613	
Benefits paid	(720)	(843)	
Actuarial (gain) loss	(160)	314	
Defined benefit obligation, end of year	11,839	11,875	

An actuarial extrapolation was performed as at December 31, 2024. As a result of this exercise, the Company decreased the accumulated liability by \$36 [December 31, 2023 - increased by \$349 based on an actuarial extrapolation].

Significant changes in actuarial assumptions related to discount rates, mortality rates and retirement age may affect the valuation of the defined benefit obligation.

12. NOTES PAYABLE

The Company currently has the following unsecured promissory notes to Hydro Ottawa Capital Corporation [December 31, 2023 - Hydro Ottawa Holding Inc.]:

2024

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\$	2023		
\$			
4.97% promissory note, due December 19, 2036	50,000	50,000	
4.14% for the first five years [3.99% thereafter] promissory note, issued May 14, 2013 and due May 14, 2043	107,185		
	107,185		
2.72% for the first five years [2.61% thereafter] promissory note, issued February 9, 2015 and due February 3, 2025	138,667		
	138,667		
3.77% for the first five years [3.64% thereafter] promissory note, issued February 9, 2015 and due February 2, 2045	121,333		
	121,333		
2.72% for the first five years [2.61% thereafter] promissory note, issued June 25, 2015 and due June 25, 2025	15,999		
	15,999		
3.77% for the first five years [3.64% thereafter] promissory note, issued June 25, 2015 and due June 25, 2045	14,001		
	14,001		
2.66% promissory note, due October 16, 2029	87,500	87,500	
3.21% promissory note, due October 16, 2049	162,500	162,500	
3.57% grid promissory note issued July 5, 2021 and due on demand		80,000	
	80,000		
4.94% grid promissory note issued August 9, 2022 and due on demand		30,000	
	30,000		
4.56% grid promissory note issued July 6, 2023 and due on demand		30,000	
	30,000		
4.49% grid promissory note issued November 6, 2024 and due on demand			
60,000	-	897,185	837,185
Less: current portion	(354,666)	-	
	542,519	837,185	

The grid promissory note facility bears fixed-rate interest based on the cost of long-term debt for Ontario's Regulated Utilities in accordance with the OEB's cost of capital calculations. Hydro Ottawa Holding Inc. did not intend to recall any amounts due on demand in 2024.

The promissory notes and the grid promissory note facility are subordinated and postponed to the obligation of the Company to a third party for the payment in full of any secured indebtedness and any and all security interests granted to secure such obligations of the Company.

13. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- Ensure continued access to funding to maintain and improve the operations and infrastructure of the Company;
- Ensure compliance with covenants related to the credit facilities and senior unsecured debentures entered into by its immediate parent company, Hydro Ottawa Capital Corporation; and
- Align the Company's capital structure with the debt to equity structure recommended by the OEB. The Company's capital consists of the following:

2024

\$

2023

\$

Working capital facility	39,894	65,310
--------------------------	--------	--------

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Current portion of notes payable	354,666	-
Notes payable	542,519	837,185
Total debt	937,079	902,495
Shareholder's equity	497,507	466,113
Total capital	1,434,586	1,368,608
Debt capitalization ratio	65.32 %	65.94 %

The Company is in compliance with all financial covenants and limitations associated with its credit facilities and its long-term debt.

The Company is deemed by the OEB to have a capital structure that is funded by 56% long-term debt, 4% short-term debt and 40% equity. The OEB uses this deemed structure only as a basis for setting distribution rates. As such, the Company's actual capital structure may differ from the OEB deemed structure. The Company met its capital management objectives, which have not changed during the year.

14. SHARE CAPITAL

(a) Authorized

Unlimited number of voting first preferred shares, redeemable at one dollar per share
Unlimited number of non-voting second preferred shares, redeemable at ten dollars per share

Unlimited number of non-voting third preferred shares, redeemable at one hundred dollars per share

Unlimited number of voting fourth preferred shares [ten votes per share], redeemable at one hundred dollars per share
Unlimited number of voting Class A common shares
Unlimited number of non-voting Class B common shares

Unlimited number of non-voting Class C common shares, redeemable at the price at which such shares are issued

The above shares are without nominal or par value.

Holder of second preferred shares, fourth preferred shares and common shares are entitled to receive dividends as and when declared by the Board of Directors at their discretion.

(b) Issued

2024

\$

2023

\$

154,789,001 Class A common shares 167,081 167,081

Any invitation to the public to subscribe for shares of the Company is prohibited by shareholder resolution.

On April 23, 2024, the Board of Directors declared a \$5,760 dividend on the common shares of the Company outstanding on December 31, 2023. The dividend was paid to the sole shareholder, Hydro Ottawa Holding Inc. on April 30, 2024. No dividends were declared by the Board of Directors in 2023.

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Fair value disclosures

The carrying value of the Company's financial instruments, except for notes payable, approximates fair value because of the short maturity and nature of the instruments. The fair value measurement of the financial instrument for

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which the fair value has been disclosed is included in Level 2 of the fair value hierarchy [Note 3(e)].

The Company has estimated the fair value of the notes payable as at December 31, 2024 as amounting to \$843,345 [2023 - \$765,259]. The fair value has been determined based on discounting all estimated future repayments of principal and interest required to fully repay the notes payable at the estimated interest rate of 4.40% [2023 - 4.60%] that would be available to the Company on December 31, 2024.

(b) Market risk

The Company is exposed to market risk, which is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market prices are comprised of three types of risks: interest rate risk, foreign exchange risk and commodity price risk. As the Company has not entered into significant hedging transactions or derivative contracts, there is no exposure to commodity price risk.

i. Interest rate risk

The Company is exposed to interest rate risk on its borrowings. The Company mitigates exposure to interest rate risk by fixing interest rates on its notes payable with its immediate parent company. Under Hydro Ottawa Capital Corporation's credit facilities, any advances on its operating line would expose the Company to fluctuations in short term interest rates related to prime rate loans and CORRA loans [2023 - bankers' acceptances] as all short-term financing requirements are obtained through its immediate parent company, which passes on its borrowing costs. The interest rate risk is deemed to be low due to the immaterial cost of its short-term borrowings. For the most part, the borrowing requirements are for a very short duration as the advances serve to bridge gaps between the cash outflow related to the monthly power bill and the inflows related to the settlements with customers and, as such, there is very limited exposure to interest rate risk.

The Company is also exposed to fluctuations in interest rates as its regulated rate of return is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

A sensitivity analysis was conducted to examine the impact of a change in the prime rate on the Company's advances from Hydro Ottawa Capital Corporation. A variation of 1% [100 basis points], with all other variables held constant, would increase or decrease the annual interest expense by approximately \$506.

ii. Foreign exchange risk

At December 31, 2024, the Company has limited exposure to fluctuations in foreign currency exchange rates. The Company does purchase a small proportion of goods and services that are denominated in foreign currencies, predominately the US dollar. The impact of the fluctuation of foreign currencies on the gains or losses of accounts payable denoted in foreign currencies is not material.

(c) Credit risk

Credit risk is the risk that a counterparty will default on its obligations, causing a financial loss to the Company. Concentration of credit risk associated with accounts receivable is limited due to the large number of customers the Company services. The Company has approximately 372,000 customers, the majority of which are residential. As a result, the Company did not earn a significant amount of revenue and does not have a significant receivable from any individual customer.

The Company performs ongoing credit evaluations of its customers and requires collateral to support non-residential customer accounts receivable on specific accounts to mitigate significant losses in accordance with OEB

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legislation. As at December 31, 2024, the Company held security deposits related to power recovery and distribution revenue in the amount of \$14,317 [2023 - \$14,336] with respect to these customers.

The Company monitors and limits its exposure to credit risk on a continuous basis.

The Company applies the IFRS 9 - Financial Instruments simplified approach to measuring expected credit losses which uses a lifetime expected loss allowance for all trade and other receivables. The expected loss rates for trade receivables are based on the payment profiles of sales over a period of twelve months before December 31, 2024 or December 31, 2023 respectively and the corresponding historical credit losses experienced within this period and other information. The historical loss rates are adjusted to reflect current and forward-looking information on macroeconomic factors affecting the ability of the customers to settle the receivables.

On that basis, the loss allowance as at December 31, 2024 and December 31, 2023 was determined as follows for trade and other receivables.

Gross carrying amount

\$

Weighted average loss rate

Loss allowance

\$

Net carrying amount

\$

December 31, 2024

Outstanding for 30 days or less

100,776

0.00 %

-

100,776

Outstanding for more than 30 days but no more than 120 days 13,732

12.56 % 1,725 12,007

Outstanding for more than 120 days 5,285 44.82 % 2,369 2,916

Unbilled receivables relating to electricity 96,073 1.05 % 1,009

95,064 215,866 5,103 210,763

December 31, 2023

Outstanding for 30 days or less

93,099

0.00 %

-

93,099

Outstanding for more than 30 days but no more than 120 days 5,764

19.67 % 1,134 4,630

Outstanding for more than 120 days 5,371 41.39 % 2,223 3,148

Unbilled receivables relating to electricity 86,259 0.91 % 784

85,475 190,493 4,141 186,352

The following table reconciles the opening and closing loss allowance for trade and other receivables:

Balance, beginning of year 2024

\$ 2023

\$

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	4,141	4,007			
Net remeasurement of loss allowance	2,874	2,323			
Write-offs	(2,067)	(2,344)			
Recoveries of amounts previously written-off	155	155			
Balance, end of year	5,103	4,141			
<p>Impairment losses on trade and other receivables are presented as net impairment losses within the statement of income. When a receivable is deemed to be uncollectible, it is written off and the expected loss allowance is adjusted accordingly. Subsequent recoveries of receivables previously provisioned or written off result in a reduction of impairment losses included in operating costs in the statement of income.</p> <p>As at December 31, 2024, the Company's maximum exposure to credit risk is equal to the carrying value of accounts receivable less customer deposits held.</p>					
<p>(d) Liquidity risk</p> <p>Liquidity risk is the risk that the Company will not meet its financial obligations as they come due. The Company's immediate parent, Hydro Ottawa Capital Corporation, manages all the financing and investing activities for the Company. The Company has access to credit facilities with Hydro Ottawa Capital Corporation [Note 8]. These credit facilities are available to the Company to help meet its financial obligations as they come due.</p> <p>Liquidity risks associated with financial commitments are as follows:</p>					
<p>Due within one year</p> <p>\$</p>					
<p>2024</p> <p>Due between one and five years</p> <p>\$</p>					
<p>Due after five years</p> <p>\$</p>					
Working capital facility	39,894	-	-		
Accounts payable and accrued liabilities	202,289	-	-	-	Notes payable
4.97% promissory note, due December 19, 2036	-	-	50,000		
4.14% for the first five years [3.99% thereafter] promissory note, due May 14, 2043	-	-	107,185		
2.72% for the first five years [2.61% thereafter] promissory note, due February 3, 2025	138,667	-	-		
3.77% for the first five years [3.64% thereafter] promissory note, due February 2, 2045	-	-	121,333		
2.72% for the first five years [2.61% thereafter] promissory note, due June 25, 2025	15,999	-	-		
3.77% for the first five years [3.64% thereafter] promissory note, due June 25, 2045	-	-	14,001		
2.66% promissory note, due October 16, 2029	-	87,500	-		
3.21% promissory note, due October 16, 2049	-	-	162,500		
3.57% grid promissory note issued July 5, 2021 and due on demand	-	-	80,000		
- 4.94% grid promissory note issued August 9, 2022 and due on demand	30,000	-	-		
- 4.56% grid promissory note issued July 6, 2023 and due on demand	30,000	-	-		
- 4.49% grid promissory note issued November 6, 2024 and due on demand	60,000	-	-		
Interest to be paid on notes payable	21,127	76,437	252,243		

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617,976 163,937 707,262

16. REVENUE FROM CONTRACTS WITH CUSTOMERS AND OTHER SOURCES

The Company's revenue breakdown is as follows:

Revenue from contracts with customers

Power recovery and distribution

2024

\$

2023

\$

Residential service (1)	484,470	420,648
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General service (2)	655,029	604,514
---------------------	---------	---------

Large users (3)	61,128	61,513
-----------------	--------	--------

1,200,627	1,086,675
-----------	-----------

Other

Service work related to distribution operations

6,528

5,921

Pole attachment and duct rentals	4,068	3,874
----------------------------------	-------	-------

Capital contributions from customers amortized to revenue	4,562	3,829
-----------------------------------------------------------	-------	-------

Account-related charges	3,855	3,349
-------------------------	-------	-------

Shared service agreements and miscellaneous	4,686	4,933
---------------------------------------------	-------	-------

23,699	21,906
--------	--------

1,224,326	1,108,581
-----------	-----------

Revenue from other sources

Other

Investment property rentals	948	901
-----------------------------	-----	-----

Capital contributions from developers amortized to revenue	4,841	4,126
------------------------------------------------------------	-------	-------

5,789	5,027
-------	-------

1,230,115	1,113,608
-----------	-----------

(1) Residential service means a service that is for domestic or household purposes, including single family or individually metered multifamily units and seasonal occupancy.

(2) General service means a service supplied to premises other than those receiving residential service and large users and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.

(3) Large users means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

17. OPERATING COSTS

2024

\$ 2023

\$

Salaries, wages and benefits	86,024	72,570
------------------------------	--------	--------

Contracted services - distribution system maintenance	16,279	21,032
-------------------------------------------------------	--------	--------

Contracted services - customer owned plant	8,933	6,493
--------------------------------------------	-------	-------

Other electricity distribution costs	11,272	13,242
--------------------------------------	--------	--------

Other general and administrative	48,487	42,513
----------------------------------	--------	--------

Loss (gain) on disposals of property, plant and equipment	460	(469)
-----------------------------------------------------------	-----	-------

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Capital recovery	(33,762)	(26,508)	
137,693	128,873		
18. FINANCING COSTS			
2024			
\$ 2023			
\$			
Interest on long-term debt	29,391	28,278	
Short-term interest and fees	3,290	3,730	
Less: capitalized borrowing costs	(965)	(694)	
31,716	31,314		
19. INCOME TAXES			
Income tax expense recognized in net income comprises the following:			
Current tax expense			
2024			
\$			
2023			
\$			
Current income tax expense (recovery)	2,636	(257)	
Deferred income tax expense			
Origination and reversal of temporary differences	12,729	8,574	
Income tax expense recognized in net income	15,365	8,317	
Income tax expense (recovery) recognized in OCI comprises the following:			
2024			
\$			
2023			
\$			
Income tax effect of actuarial gain (loss) on defined benefit obligations	58	(113)	
The provision for income taxes differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rates. A reconciliation between the statutory and effective tax rates is provided as follows:			
2024			
\$			
2023			
\$			
Federal and Ontario statutory income tax rate	26.50 %	26.50 %	
Income attributable to equity shareholder before income taxes		52,519	
37,115			
Income taxes at statutory rate	13,918	9,835	
Increase (decrease) in income taxes resulting from:			

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Permanent differences	80	65	
Provision to return adjustment	1,326	(316)	
Current tax recovery from loss carryback	-	(888)	
Other	41	(379)	

15,365 8,317

Effective income tax rate 29.26 % 22.41 %

The Company, as a rate-regulated enterprise, is required to recognize deferred income tax assets and liabilities and related regulatory deferral account credit and debit balances for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

Significant components of the Company's net deferred income tax liability are as follows:

2024		
2023		
	\$	\$
Property, plant and equipment and intangible assets	(106,461)	(94,999)
Employee future benefits	4,269	4,281
Other	6,777	8,090
	(95,415)	(82,628)

Movements in the net deferred income tax liability balances during the year were as follows:

2024		
2023		
	\$	\$
Deferred income tax, beginning of year	(82,628)	(74,167)
Recognized in net income	(12,729)	(8,574)
Recognized in OCI related to employee future benefits	(58)	113
Deferred income tax liability, end of year	(95,415)	(82,628)

The Company's regulatory deferral account debit balance for the amounts of deferred income taxes expected to be collected from customers in future electricity rates is \$95,355 [2023 - \$82,622].

20. CHANGES IN NON-CASH WORKING CAPITAL AND OTHER OPERATING BALANCES

2024		
2023		
	\$	\$
Accounts receivable	(24,411)	(16,882)
Prepaid expenses	(2,158)	(1,792)
Accounts payable and accrued liabilities	(6,344)	16,991
Net change in accruals related to property, plant and equipment		(2,818)
408Net change in accruals related to intangible assets	996	(854)
	(34,735)	(2,129)

21. CONTINGENT LIABILITIES

Purchasers of electricity from the IESO are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by a default notice issued by the IESO. A prudential support obligation is calculated based upon a default protection amount and the distributor's trading limit less a reduction for the distributor's credit rating. As at December 31, 2024, the Company had drawn standby letters of credit in the amount of \$10,000 [2023 - \$10,000] against its credit facility to cover its prudential support obligation.

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The Company participates with other electrical utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electrical Association Reciprocal Insurance Exchange. The Company is liable for additional assessments to the extent premiums collected and reserves established are not sufficient to cover the cost of claims and costs incurred. If any additional assessments were required in the future, their cost would be charged to income in the year during which they occur.

The Company is party to connection and cost recovery agreements with HONI as described in Note 7 of these financial statements. Each of the Company's CCRAs has a term of 25 years. To the extent that the cost of a project is not recoverable from future transformation connection revenues, the Company is obligated to pay a capital contribution equal to the difference between these revenues and the construction costs allocated to the Company. These agreements require periodic reviews whereby a comparison of actual to forecasted load is conducted, and a true-up calculation performed. When a true-up calculation shows the Company's actual load for the past period and updated load forecast for the future period are lower than the initial load, the Company is obligated to make up this shortfall. When the Company's actual load and updated load forecast are higher than the initial load, the Company is entitled to a rebate. HONI is expected to perform true-up calculations in years 5 and 10 and in year 15 if the difference between the actual incremental load and initial load at the end of year 10 is greater than 20%. Various lawsuits have been filed against the Company for incidents that arose in the ordinary course of business. In the opinion of management, the outcomes of the lawsuits, now pending, are neither determinable nor material. Should any loss result from the resolution of these claims, such losses would be claimed through the Company's insurance carrier, with any unrecoverable amounts charged to income in the year of resolution.

22. COMMITMENTS

As at December 31, 2024, the Company has \$198,023 in total open commitments spanning between 2025 and 2031. These include commitments relating to IT infrastructure management services, construction projects, overhead and underground services and other services relating to the Company's operations.

23. RELATED PARTY TRANSACTIONS

Transactions with related parties occur in the normal course of business, and are transacted at the amount of consideration determined and agreed to by the related parties. Trade amounts due from and to related parties are non-interest bearing, result from normal operations and are due within one year.

(a) Transactions with ultimate shareholder and its subsidiaries
During the year, the Company earned power recovery and distribution revenue from the City of Ottawa and its subsidiaries, which was billed at prices and terms approved by the OEB. In addition, the Company earned commercial services revenue from the City of Ottawa and its subsidiaries totaling \$193 [2023 - \$294]. The Company also received \$1,025 [2023 - \$4,235] in contributions relating to the upgrade and/or expansion of the Company's existing electricity distribution infrastructure.

The Company incurred \$3,230 [2023 - \$3,399] in property taxes and purchased \$1,065 [2023 - \$994] in fuel, permits and other services during the year, which is included in operating costs. The Company also incurred \$523 [2023 - \$55] in building permit costs and development charges, which are included in property, plant and equipment.

As at December 31, 2024, the Company's accounts receivable and customer deposits include \$8,399 [2023 - \$8,605] and \$2,090 [2023 - \$1,866], respectively, while the Company's accounts payable and accrued liabilities include \$94 [2023 -

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\$152] due to the City of Ottawa and its subsidiaries in respect of the transactions described above.

(b) Transactions with ultimate parent company

During the year, the Company earned revenue of \$1,578 [2023 - \$1,335] from Hydro Ottawa Holding Inc. relating to the provision of administrative and corporate services.

The Company incurred \$4,222 [2023 - \$6,437] in operating costs related to the purchase of administrative and corporate support services that includes compensation for certain key management personnel, and \$2,685 [2023 - \$3,717] in short-term financing costs, net of interest income.

At December 31, 2024, the Company's accounts payable and accrued liabilities include \$1,676 [2023 - \$2,980] due in respect of the transactions described.

The Company incurred \$21,695 [2023 - \$28,278] in financing costs during the year on its notes payable to Hydro Ottawa Holding Inc. described in Note 12 of these financial statements.

(c) Transactions with immediate parent

Since October 1, 2024, the Company incurred \$2,618 [2023 - \$nil] in operating costs related to the purchase of administrative and corporate support services that includes compensation for certain key management personnel, and \$546 [2023 - \$nil] in short-term financing costs, net of interest income, from Hydro Ottawa Capital Corporation [Note 1].

At December 31, 2024, the Company's accounts payable and accrued liabilities include \$2,802 [2023 - \$nil] due in respect of the transactions described.

The Company incurred \$7,696 [2023 - \$nil] in financing costs during the year on its notes payable to Hydro Ottawa Capital Corporation described in Note 12 of these financial statements.

(d) Transactions with other related parties

During the year, the Company earned revenue from the sale of electricity to other related parties, which is billed at prices and terms approved by the OEB, and earned other revenue of \$3,434 [2023 - \$4,062]. The Company also received \$16,533 [2023 - \$343] in contributions relating to the upgrade and/or expansion of the Company's existing electricity distribution infrastructure.

During the year, the Company purchased power of \$16,825 [2023 - \$13,499], acquired property, plant and equipment of \$1,794 [2023 - \$2,200], and incurred \$492 [2023 - \$411] in operating costs.

In 2023, the Company sold investment property to a related party for cash proceeds of \$523. No gain or loss was recognized on the transaction.

At December 31, 2024, the Company's accounts receivable include \$7,916 [2023 - \$837] due in respect of the transactions above while accounts payable and accrued liabilities and customer deposits include \$3,911 [2023 - \$3,974] and \$9,703 [2023 - \$nil], respectively, due to other related parties.

24. SUBSEQUENT EVENTS

On February 3, 2025, \$338,667 of the Company's unsecured promissory notes, which Hydro Ottawa Capital Corporation assumed on October 1, 2024, came due or were called. To replace these existing promissory notes, the Company issued a \$350,000, 4.43% promissory note to Hydro Ottawa Capital Corporation on the same day. This new note is due on January 30, 2035.

On April 24, 2025, the Board of Directors declared a \$7,431 dividend on the common shares of the Company outstanding on December 31, 2024.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIF1

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro Ottawa Limited/Hydro Ottawa Limitee		2024-12-31

Assets – lines 1000 to 2599

1060	210,763,000	1066	411,000	1484	8,330,000
1599	219,504,000	1680	172,121,000	1681	-26,783,000
1740	1,952,886,000	1741	-428,374,000	1900	442,000
2008	2,125,449,000	2009	-455,157,000	2010	180,244,000
2011	-78,040,000	2178	180,244,000	2179	-78,040,000
2420	140,811,000	2589	140,811,000	2599	2,132,811,000

Liabilities – lines 2600 to 3499

2620	202,289,000	2860	39,894,000	2920	354,666,000
2960	10,266,000	3139	607,115,000	3140	542,519,000
3220	327,199,000	3240	95,415,000	3270	11,839,000
3320	51,217,000	3450	1,028,189,000	3499	1,635,304,000

Shareholder equity – lines 3500 to 3640

3500	167,081,000	3600	330,426,000	3620	497,507,000
3640	2,132,811,000				

Retained earnings – lines 3660 to 3849

3660	299,032,000	3680	37,154,000	3700	-5,760,000
3849	330,426,000				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIF1

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro Ottawa Limited/Hydro Ottawa Limitee		2024-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	1,236,070,000	8089	1,236,070,000	8210	-460,000
8299	1,235,610,000				

Cost of sales – lines 8300 to 8519

8320	940,048,000	8518	940,048,000	8519	296,022,000
-------------	-------------	-------------	-------------	-------------	-------------

Operating expenses – lines 8520 to 9369

8570	9,348,000	8670	58,852,000	8740	31,716,000
9010	11,272,000	9060	86,024,000	9110	25,212,000
9270	5,894,000	9284	14,725,000	9367	243,043,000
9368	1,183,091,000	9369	52,519,000		

Extraordinary items and taxes – lines 9970 to 9999

9970	52,519,000	9990	2,636,000	9995	12,729,000
9999	37,154,000				

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
------------------------------------------------------------------------	-------------------------------	----------------------------------------------

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see Guide T4012, T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.
- If you need more space, attach additional schedules.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125	37,154,000	A1
Net income (loss) after extraordinary items from line 110 of Schedule 150	0	A2
Total	37,154,000	A

Add:

Provision for income taxes – current	101	2,636,000	
Provision for income taxes – deferred	102	54,382	
Interest and penalties on taxes	103	39,474	
Amortization of tangible assets	104	58,852,000	
Amortization of intangible assets	106	9,348,000	
Loss on disposal of assets	111	1,059,256	
Charitable donations and gifts from Schedule 2	112	50,152	
Taxable capital gains from Schedule 6	113	108,524	
Scientific research expenditures deducted per financial statements	118	6,152,526	
Non-deductible meals and entertainment expenses	121	124,634	
Other reserves on lines 270 and 275 from Schedule 13	125	6,775,541	
Reserves from financial statements – balance at the end of the year	126	5,102,888	
Subtotal of additions		90,303,377	▶ 90,303,377

Add:

Other additions:

	1 Description	2 Amount		
	605	295		
1	Inducement under 12(1)(x) ITA	37,993		
2	Employee Future Benefits expensed in F/S	843,200		
3	Bonus accrual not paid in 180 days after the YE	102,793		
4		0		
5	Legal fees on land sale expensed for accounting	15,613		
	Total of column 2	999,599	▶ 296	999,599
			199	999,599 ▶ 999,599 D
			500	91,302,976 ▶ 91,302,976
				128,456,976 B

Amount A plus line 500

Deduct:

Capital cost allowance from Schedule 8	403	87,994,435	
SR&ED expenditures claimed in the year on line 460 from Form T661	411	10,950,636	
Other reserves on line 280 from Schedule 13	413	7,582,888	
Reserves from financial statements – balance at the beginning of the year	414	4,140,541	
Subtotal of deductions		110,668,500	▶ 110,668,500

Deduct:

Other deductions:

	1 Description 705	2 Amount 395			
1	AFUDC [13(7.4) election]	964,805			
2	Employee Future Benefits paid during the year	719,500			
3	Deferred Revenue Amortization	9,006,939			
4	IBM lease payment	98,900			
5	ITC recorded in P&L	146,176			
6	Current SRED exp capitalized in acctg	4,540,826			
7	Prior year bonus true up - accounting	65,272			
	Total of column 2	<u>15,542,418</u>	▶	396	<u>15,542,418</u>
				Subtotal of other deductions	499 <u>15,542,418</u> ▶ <u>15,542,418</u> E
				Total deductions	510 <u>126,210,918</u> ▶ <u>126,210,918</u>
	Net income (loss) for income tax purposes (amount B minus line 510)				<u>2,246,058</u> C

Enter amount C on line 300 of the T2 return.

Excessive Interest and Financing Expenses Limitation

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year end Year Month Day 2024-12-31
-----------------------------------------------------------------	-------------------------------	----------------------------------------------

- Use this schedule to determine the deductibility of **interest and financing expenses** (IFE) under the excessive interest and financing expenses limitation (EIFEL) rules and to provide information on **exempt interest and financing expenses** (exempt IFE).
- The main provisions of the EIFEL rules are paragraph 12(1)(l.2), sections 18.2 and 18.21, and clause 95(2)(f.11)(ii)(D).
- The ratio of permissible expenses is 40% for tax years that start on or after October 1, 2023 but before January 1, 2024. For tax years that start on or after January 1, 2024, the ratio of permissible expenses is 30%.
- All legislative references are to the Income Tax Act.
- File this schedule with your T2 Corporation Income Tax Return for the tax year.

Part 1A – Received capacity

1. Does the corporation have received capacity as defined in subsection 18.2(1) in the year? **001** Yes No

If line 001 is **yes**, complete the following table.

Row	1 Name of each eligible group entity the corporation received capacity from	2 Account number	3 Tax year end (yyyy/mm/dd)	4 Amount of capacity received
1	002	003	004	005

Total of column 4 (enter on line 130 in Part 2J and line 136 in Part 2K) _____ A

Part 1B – Exempt IFE

1. Has the corporation incurred any amounts for a borrowing or other financing that are exempt IFE as defined in subsection 18.2(1)? **006** Yes No

If line 006 is **yes**, complete the following table.

Row	1 Name of public sector authority with which an agreement has been entered into	2 Principal amount of borrowing or other financing entered into as a result of the agreement	3 IFE incurred regarding amount in column 2 (see note 1)	4 Corporation income from activities that the amount in column 2 wholly or partially funded	5 Corporation loss from activities that the amount in column 2 wholly or partially funded (enter as positive amount)
	007	008	009	010	011
1					

Total of column 3 _____ A

Total of column 4 (enter on line 104 in Part 2F) _____ B

Total of column 5 (enter on line 092 in Part 2F) _____ C

Note 1: IFE determined as if the description of variable A in the definition of IFE were read without reference to exempt IFE.

Part 1C – Information on borrowings and other financings and related derivatives

Complete the following table if the corporation has a borrowing or other financing.

1 Relationship with others parties	2 Total of the principal amounts of borrowing or other financing at any point in the tax year	3 Total of the notional amounts of derivatives entered into in respect of a borrowing or other financing at any point in the tax year	4 Total of all amounts included in paragraph (a) of variable A of IFE in respect of a borrowing or other financing	5 Total of all amounts included in paragraph (e) of variable A of IFE (other than a loss or capital loss)	6 Total of all amounts included in paragraph (a) of variable B of IFE (other than a dividend or exempt IFE or a gain included in taxpayer income)
	012	013	014	015	016
Canadian arm's length					
Canadian non-arm's length	937,079,000		32,681,114		
Non-resident arm's length					
Non-resident non-arm's length					

Total of column 4 (enter on line 027 in Part 2A) 32,681,114 A

Total of column 5 (enter on line 033 in Part 2A) _____ B

Total of column 6 (enter on line 042 in Part 2A) _____ C

Part 1D – Information on loans and other financings and related derivatives

Complete the following table if the corporation has a loan or other financing.

1 Relationship with others parties	2 Total of the principal amounts of loans or other financings at any point in the tax year 017	3 Total of the notional amounts of derivatives entered into in respect of loans or other financings at any point of the year 018	4 Total of all amounts included in paragraph (d) of variable A of IFR (other than a dividend or a gain included in corporation's income) 019	5 Total of all amounts included in paragraph (a) of variable B of IFR (other than a loss or capital loss) 020
Canadian arm's length				
Canadian non-arm's length				
Non-resident arm's length				
Non-resident non-arm's length				
Total of column 4 (enter on line 061 in Part 2D)			===== A	
Total of column 5 (enter on line 066 in Part 2D)			===== B	

Part 1E – IFE allocated from partnership

Complete the following table if the corporation is a member of a partnership that has IFE.

Row	1 Name of the partnership 021	2 Partnership account number (leave blank if the partnership is non-resident) 022	3 Corporation's share of amount included under variable A of partnership IFE (box 247 of the T5013 slips if applicable) 023	4 Portion of amount in column 3 in which paragraph 12(1)(l.1) applies 024	5 Portion of amount in column 3, not deductible in the corporation's income or included in corporation's non-capital loss because of subsection 96(2.1) 025	6 Amount to be included under paragraph (h) of variable A of IFE (column 3 minus column 4 minus column 5) 026
1						
Total of column 6 (enter on line 039 in Part 2A, line 142 in Part 2L and line 156 in Part 2N)						===== A

Part 2A – Interest and financing expenses (IFE)

Variable A: Total of all amounts (other than an amount included in exempt IFE), each of which is:

An amount (other than **excluded interest**, deemed interest under subsection 137(4.1), or an amount included in any other line below), that is,

Interest paid or payable on a borrowing or other financing (excluding shares) (amount A from Part 1C) **027** 32,681,114
Interest paid or payable – other **028**

An amount that, on the assumption that it is not deductible under another section, would be deductible under subparagraphs 20(1)(e)(ii), 20(1)(e)(ii.1), 20(1)(e)(ii.2) and paragraphs 20(1)(e.1), 20(1)(e.2) and 20(1)(f) **029**

Amount attributable to IFE that your corporation has claimed for the particular tax year as:

Capital cost allowance (CCA) (amount B from Part 2B) **030**
Resource expenses (amount A from Part 2C) **031**
Terminal loss (amount A from Part 2B) **032**

An amount, under or as a result of an agreement or arrangement entered into as or in relation to a borrowing or other financing of the corporation (or a non-arm's length person or partnership) that can reasonably be considered to increase or be part of the cost of funding with respect to the borrowing or other financing of the corporation (or a non-arm's length person or partnership), that is,

Paid or payable that is deductible in the tax year (other than under subparagraph 20(1)(e)(i)) (amount B from Part 1C) **033**
A loss that is deductible in the tax year (other than under subparagraph 20(1)(e)(i)) **034**
A capital loss that reduces the amount determined under paragraph 3(b) or deducted when calculating the corporation's taxable income for the tax year **035**

Expense or fee payable (other than an amount already included on line 029) under (or in contemplation of, in the course of entering into, or in relation to) an agreement or an arrangement that gives rise to, or can reasonably be expected to give rise to,

An amount being included in IFE – under paragraph (e) of variable A of the definition of IFE **036**
An amount that reduces the IFE for the year under variable B of the definition of IFE **037**

A **lease financing amount** (other than an **excluded lease** and excluded interest) **038**

The corporation's share of the IFE of a partnership it is a member of (amount A from Part 1E) **039**

The portion of an amount claimed under paragraph 111(1)(e) that was denied under subsection 96(2.1) in a preceding tax year that is attributable to IFE **040**

An amount that is a controlled foreign affiliate's (CFA) **relevant affiliate interest and financing expenses**, to the extent of the corporation's **specified participating percentage** in respect of the affiliate for the affiliate tax year (enter on line 143 in Part 2L) . **041**

Total of lines 027 to 041 (enter on lines 139 in Part 2K and 141 in Part 2L) 32,681,114 A

Variable B

An amount, under or as a result of an agreement or arrangement entered into as or in relation to a borrowing or other financing of the corporation (or a non-arm's length person or partnership) that can reasonably be considered to reduce the cost of funding with respect to the borrowing or other financing of the corporation (or a non-arm's length person or partnership), that is,

Received or receivable (other than as a dividend or exempt IFE) included in computing the corporation's income for the year (amount C from Part 1C) **042**
A gain included in the corporation's income for the year **043**

to the extent the amount is not sheltered from Canadian tax by virtue of a credit or deduction in respect of foreign taxes.

The corporation's share of an amount that, if received or receivable by the corporation, would meet the description of an amount to be included on lines 042 or 043, but that is received or receivable by a partnership of which the corporation is a member (total of amounts from box 249 of the T5013 slips plus relevant amounts from non-resident partnerships) **044**

Total of lines 042 to 044 _____ B

Total IFE. Amount A minus Amount B. If negative, enter "0".
(enter on line 083 in Part 2F, line 113 in Part 2G, line 117 in Part 2H and on line 131 in Part 2K) **045** 32,681,114

Part 2B – Capitalized IFE in the cost of depreciable assets

Complete the following table if the corporation has an amount that is paid or payable on or after February 4, 2022, that is attributable to IFE and is part of the capital cost of depreciable assets.

Row	1 Class number	2 IFE in undepreciated capital cost (UCC) at beginning of the tax year	3 IFE in the cost of acquisitions, adjustments and transfers, and proceeds of dispositions	4 IFE in UCC (column 2 plus or minus column 3) If negative, enter "0"	5 IFE in terminal loss (see note 2)	6 IFE in CCA (cannot be more than column 4)	7 IFE in UCC at the end of the year (column 4 minus column 6) If negative, enter "0"
	046	047	048	049	050	051	052
1							
Note 2: If no property is left in the class at the end of the year and there is still a positive amount in column 4, you have a terminal loss. If applicable, enter the positive amount from column 4 in column 5.					Total of column 5 (enter on line 032 in Part 2A) _____ A Total of column 6 (enter on line 030 in Part 2A) _____ B		

Part 2C – IFE included in resource deductions

Complete the following table if the corporation has an amount that is paid or payable on or after February 4, 2022, that is attributable to IFE and is included in a resource expense pool.

Row	1 Resource expenses (see note 3)	2 IFE in the opening balance	3 IFE in amounts added or deducted from pool balance during the tax year	4 IFE in amount available before current year claim (column 2 plus or minus column 3) If negative, enter "0"	5 IFE in current year claims (cannot be more than column 4)	6 IFE in closing balance (column 4 minus column 5) If negative, enter "0"
		053	054	055	056	057
1	Cumulative Canadian exploration expenses (CCEE) – regular expenses					
2	CCEE – successor expenses					
3	Cumulative Canadian development expenses (CCDE) – regular expenses					
4	CCDE – successor expenses					
5	Cumulative Canadian oil and gas property expenses (CCOGPE) – regular expenses					
6	CCOGPE – successor expenses					
7	Foreign exploration and development expenses (FEDE) – regular expenses					
8	FEDE – successor expenses					
9	Cumulative foreign resource expenses (CFRE) – regular expenses					
10	CFRE – successor expenses					
Note 3: Expenses incurred by the corporation are referred to as regular expenses and expenses incurred by the predecessor corporation that a successor corporation is entitled to claim are referred to as successor expenses .					Total of column 5 (enter on line 031 in Part 2A) _____ A	

Part 2D – Interest and financing revenues (IFR)

Variable A: Total of all amounts (other than an amount included under variable B of the definition of IFE), each of which is:

Interest received or receivable (other than excluded interest, deemed interest under subsection 137(4.1), or an amount included in any of the other lines in Part 2D)	058	1,057,449
Amount included in the income because of subsection 12(9) or section 17.1 (other than an amount included in any of the other lines in Part 2D)	059	
Fee or similar amount in respect of a guarantee or a similar credit support for the payment of any amount on a debt obligation owing by another person or partnership that is included in computing the corporation's income for the year (other than an amount included in any of the other lines in Part 2D)	060	
An amount, under or as a result of a agreement or arrangement, entered into as or in relation to a loan or other financing, owing to or provided by the corporation (or a non-arm's length person or partnership) that can reasonably be expected to increase or be part of the return of the corporation (or a non-arm's length person or partnership), that is,		
Received or receivable (other than as a dividend) included in computing the corporation's income for the year (amount A from Part 1D)	061	
A gain included in the corporation's income for the year	062	
A lease financing amount (other than a lease that would meet the definition of an excluded lease in subsection 18.2(1), if that definition were read without regard to paragraph (a)) that is included in income, that is not excluded interest for the year	063	
The corporation's share of the IFR of a partnership it is a member of (total of amounts from box 248 of the T5013 slips plus relevant amounts from non-resident partnerships)	064	
Amount that is a CFA's relevant affiliate interest and financing revenues, to the extent of the corporation's specified participating percentage in respect of the affiliate for the affiliate tax year, less any deduction in respect of foreign accrual tax	065	
Total of lines 058 to 065		<u>1,057,449</u> A

Variable B: Total of all amounts, each of which is:

Under or as a result of an agreement or arrangement entered into as or in relation to a loan or other financing, owing to or provided by the corporation (or a non-arm's length person or partnership) that can reasonably be considered to reduce the return in respect of the loan or financing of the corporation (or a non-arm's length person or partnership), that is,		
An amount paid or payable (other than a loss or capital loss) that is deductible in computing the corporation's income for the year (amount B from Part 1D)	066	
A loss that is deductible in computing the corporation's income for the year	067	
A capital loss that reduces the amount determined under paragraph 3(b) for the tax year	068	
The corporation's share of an amount that, if received or receivable by the corporation, would correspond the description of an amount to be included on lines 066, 067 and 068, but that is received or receivable by a partnership of which the corporation is a member (total of amounts from box 250 of the T5013 slips plus relevant amounts from non-resident partnerships)	069	
An amount otherwise included in the corporation's IFR (amount A), to the extent the amount is sheltered from Canadian tax by virtue of a credit or deduction in respect of foreign taxes, other than a credit or deduction in respect of foreign withholding taxes	070	
Amounts included in amount A of Part 2D that are exempt from tax under Part I of the Income Tax Act	071	
Total of lines 066 to 071		B
Total IFR. Amount A minus amount B. If negative, enter "0". (enter on line 096 in Part 2F, line 109 in Part 2G, line 121 in Part 2H and line 135 in Part 2K.)	072	<u>1,057,449</u>

Part 2E – Paragraph (h) of variable B of adjusted taxable income

Complete this section if the corporation is deducting an amount under paragraph 111(1)(a) for a non-capital loss that is not a specified pre-regime loss defined in subsection 18.2(1).

Row	1 Tax year of origin of the non-capital loss	2 Non-capital loss (amount determined under (i) of variable J)	3 Amounts determined under (ii) of variable J	4 Variable J (lesser of column 2 and column 3)	5 Amount deducted under paragraph 111(1)(a) when calculating taxable income for the year	6 Amount determined for paragraph (h) of variable B of the adjusted taxable income (column 5 multiplied by column 4 divided by column 2)
	073	074	075	076	077	078
1						
Total of column 6 (enter on line 089 in Part 2F)						_____ A

Part 2F – Adjusted taxable income (ATI)

Variable A

If corporation is a non-resident, the corporation's taxable income earned in Canada (determined without regard to subsection 18.2(2), paragraphs 12(1)(l.2) and 111(1)(a.1)). In any other case, the corporation's taxable income (determined without regard to subsection 18.2(2), paragraphs 12(1)(l.2) and 111(1)(a.1) and clause 95(2)(f.11)(ii)(D))

.....	079	2,108,802
Non-capital loss for the year (determined without regard to subsection 18.2(2), paragraphs 12(1)(l.2) and 111(1)(a.1) and clause 95(2)(f.11)(ii)(D))	080	
Total of all amounts determined under paragraph (b) of variable E of the ATI for CFAs of the corporation	081	
Total of all amounts determined under paragraph (b) of variable E of the ATI for CFAs of partnerships of which the corporation or a CFA of the corporation is a member	082	

Total of lines 080 to 082 ▶ A

Line 079 **minus** amount A (can be positive or negative amount) 2,108,802 B

Variable B

The corporation's IFE for the year (line 045 from Part 2A)	083	32,681,114
Amounts deducted when calculating income under paragraphs 20(1)(a) and 59.1(a), subsections 66(4), 66.1(2) or (3), 66.2(2), 66.21(4), 66.4(2), or 66.7(1), (2), (2.3), (3), (4) or (5), other than any portion already included in IFE	084	87,994,435
Terminal loss deducted under subsection 20(16) when calculating income for the year, other than any portion already included in IFE	085	
The corporation's share of the CCA or terminal loss of a partnership it is a member of (other than the portion that is already included in IFE), minus the portion of the amount that is not deductible when calculating the corporation's income or non-capital loss for the year because of subsection 96(2.1)	086	
If an amount has been deducted under paragraph 111(1)(e), the portion of the amount deducted that can reasonably be considered to be attributable to the CCA or terminal loss of a partnership (other than any portion that has been included in IFE)	087	
Amount deducted under paragraph 110(1)(k) when calculating taxable income for the year	088	
The portion of non-capital loss being deducted under paragraph 111(1)(a) that can reasonably be considered to be derived from IFE (amount A from Part 2E)	089	
25% of the amount deducted for a specified pre-regime loss under paragraph 111(1)(a) (see note 4)	090	
Additional amount, if any, that would be included in the corporation's income, in respect of a CFA or a CFA of a partnership of which the corporation or a CFA of the corporation is a member of, if the affiliate's foreign accrual property income (FAPI) was increased by an amount determined by the formula L x M/N contained in paragraph (j) of variable B of the definition of the ATI	091	
The corporation's loss if it had no income or loss other than a loss that can reasonably be considered to be from activities funded by a borrowing that results in exempt IFE (amount C from Part 1B)	092	
The corporation's share of the loss of a partnership it is a member of, if the partnership had no income or loss other than a loss that can reasonably be considered to be from activities funded by a borrowing that results in exempt IFE	093	
An amount deducted under subsections 127(5) or (6), 127.44(3), 127.45(6), 127.48(3) or 127.49(6) for a property acquired in a preceding tax year that the corporation did not include in income for the year or for a preceding year and did not include in the ATI for a preceding year to the extent it is included in an amount determined under paragraph 13(7.1)(e) and subparagraphs 53(2)(c)(vi) to (c)(vi.4) or (h)(ii) in the definition undepreciated capital cost in subsection 13(21)	094	
An amount described in clause 12(1)(x)(i)(C) or subparagraph 12(1)(x)(ii) that the corporation received, to the extent it reduces the cost or capital cost of property and is not included when calculating the corporation's income of the year under subparagraph 12(1)(x)(vi) or (vii)	095	

Total of lines 083 to 095. If negative, enter "0". 120,675,549 C

Part 2F continues on the next page >>

Note 4: Paragraph (i) of variable B of ATI in subsection 18.2(1) requires that a specified pre-regime loss election form (T2228) be filed.

Part 2F – Adjusted taxable income (ATI) (continued)

Variable C	
IFR of the corporation for the year (line 072 from Part 2D)	096 1,057,449
Recaptured depreciation amount under subsection 13(1)	097
The corporation's share of the recaptured depreciation amount of a partnership of which it is a member	098
Amount included under subsection 59(1) or (3.2) or paragraph 59.1(b) in computing income for the year	099
Foreign-source income, to the extent it is sheltered from Canadian tax by foreign tax credits under subsection 126(1) or (2)	100
Amount included under section 110.5 in computing the corporation's taxable income for the year	101
Amount included in income of the corporation under subsection 104(13), less any portion designated under subsection 104(19) or any amount that gives rise to a deduction under paragraph 94.2(3)(a) in computing FAPI	102
Amount of taxable income for the year that is not, because of an Act of Parliament, subject to tax under Part I of the Income Tax Act	103
Income of the corporation if it had no income or loss other than income that can reasonably be considered to derive from activities funded by a borrowing that results in exempt IFE (amount B from Part 1B)	104
Corporation's share of the income or loss of a partnership of which it is a member, if the partnership had no income or loss other than income that can reasonably be considered to derive from activities funded by a borrowing that results in exempt IFE	105
Total of lines 096 to 105. If negative, enter "0" .	<u>1,057,449</u> D
ATI of the corporation for the year. Amount B plus amount C minus amount D. If negative, enter "0" . (enter on line 107 in Part 2G, line 119 in Part 2H, and line 133 in Part 2K)	106 <u>121,726,902</u>

Part 2G – Excess capacity

If a **group ratio** election under subsection 18.21(2) has been made, the excess capacity is nil, in any other case:

ATI of the corporation for the year (line 106 from Part 2F)	107	121,726,902	
The ratio of permissible expenses of the corporation for the year	108	30 %	
		Line 107 multiplied by line 108	<u>36,518,071</u> ▶ <u>36,518,071</u> A
IFR of the corporation for the year (line 072 from Part 2D)	109	1,057,449	
The amount by which the IFR exceeds the IFE for the year. If negative, enter "0"	110		
If, in the absence of section 257, the ATI is a negative amount, the absolute value of ATI, otherwise nil	111		
		The lesser of lines 110 and 111	B
The ratio of permissible expenses of the corporation for the year	112	30 %	
		Amount B multiplied by line 112	▶ C
		Line 109 minus amount C. If negative, enter "0" .	<u>1,057,449</u> ▶ <u>1,057,449</u> D
		Amount A plus amount D	<u>37,575,520</u> E
The corporation's IFE for the year (line 045 from Part 2A)	113	32,681,114	
		Amount E minus line 113. If negative, enter "0" . (enter on line 129 in Part 2J)	<u>4,894,406</u> F
The restricted interest and financing expenses deductible under paragraph 111(1)(a.1) for the year (amount B from Part 2J)	114		
		Excess capacity for the current year. Amount F minus line 114. If negative, enter "0" . (enter on line 126 in Part 2I)	<u>4,894,406</u> 115

Part 2H – Absorbed capacity

Cumulative unused excess capacity determined as if the absorbed capacity for the year were nil (amount B in Part 2I)	116	17,551,180	
The corporation's IFE for the year (line 045 in Part 2A)	117	32,681,114	
If the corporation has made a group ratio election under subsection 18.21(2), the allocated group ratio amount	118		
If it has not made a group ratio election, the ATI (line 106 from Part 2F)	119	121,726,902	
Ratio of permissible expenses for the year	120	30 %	
		Line 119 multiplied by line 120	<u>36,518,071</u> ▶ <u>36,518,071</u> A
The corporation's IFR for the year (line 072 from Part 2D)	121	1,057,449	
		Either line 118 or amount A, whichever applies, plus line 121	<u>37,575,520</u> ▶ <u>37,575,520</u> B
		Line 117 minus amount B. If negative, enter "0" .	▶ C
		Absorbed capacity. The lesser of line 116 or amount C. (enter on line 127 in Part 2I and on line 138 in Part 2K)	<u>17,551,180</u> D

Part 2I – Cumulative unused excess capacity (CUEC)

If the corporation has been subject to a loss restriction event, the CUEC for any tax year after the event, is determined without regard to the absorbed capacity, excess capacity and transferred capacity for the tax years ending before the event.

Row		1 Excess capacity	2 Amounts previously transferred under subsection 18.2(4)	3 Amounts previously absorbed under subsection 18.2(2)	4 Column 1 minus column 2 minus column 3 If negative, enter "0"
		122	123	124	125
1	Third immediately preceding year	7,444,657			7,444,657
2	Second immediately preceding year	5,212,117			5,212,117
3	First immediately preceding year				
Total of column 4					<u>12,656,774</u> A
Excess capacity for the year (line 115 from Part 2G)			126	4,894,406	
CUEC determined as if the absorbed capacity for the year were nil.					
Amount A plus line 126 (enter on line 116 in Part 2H)				<u>17,551,180</u>	▶ <u>17,551,180</u> B
Absorbed capacity (amount D from Part 2H)					127
					<u>17,551,180</u> C
CUEC. Amount B minus line 127. If negative, enter "0" .					<u>17,551,180</u> C

Part 2J – Restricted interest and financing expenses (RIFE) under paragraph 111(1)(a.1)

RIFE from previous tax years		128		
Corporation's excess capacity for the year if the amount determined for C in that definition were nil (amount F from Part 2G)		129	4,894,406	
Total of all amounts of the corporation's received capacity for the year (amount A from Part 1A)		130		
			Line 129 plus line 130	<u>4,894,406</u> ▶ <u>4,894,406</u> A
			RIFE deductible under paragraph 111(1)(a.1) for the year. The lesser of line 128 and amount A (enter on line 114 in Part 2G and on line 137 in Part 2K)	<u>4,894,406</u> B

Part 2K – Proportion determined under subsection 18.2(2)

The corporation's IFE for the year (line 045 from Part 2A)	131	32,681,114
If a group ratio election under subsection 18.21(2) has been made, the amount determined and allocated in respect of the corporation for the year under the group ratio election	132	
If no group ratio election has been made, the ATI (line 106 from Part 2F)	133	121,726,902
Ratio of permissible expenses	134	30 %
Line 133 multiplied by line 134		<u>36,518,071</u> ▶ 36,518,071 A
Either line 132 or amount A, whichever applies		<u>36,518,071</u> B
The corporation's IFR for the year (line 072 from Part 2D)	135	1,057,449
Received capacity for the year (amount A from Part 1A)	136	
RIFE deductible under paragraph 111(1)(a.1) for the year (amount B from Part 2J)	137	
The amount of received capacity that exceeds the deductible amount under paragraph 111(1)(a.1). Line 136 minus line 137. If negative, enter "0" .		▶ _____ C
Absorbed capacity amount for the year (amount D from Part 2H)	138	
Amount B plus line 135 plus amount C plus line 138		<u>37,575,520</u> D
Line 131 minus amount D		_____ E
If IFE does not include any amount for relevant affiliate interest and financing expenses:		
Variable A of IFE (amount A from Part 2A)	139	32,681,114
In all other situations:		
Variable A of IFE, adjusted to remove any amounts that are part of a CFA's relevant affiliate interest and financing expenses under variable B of IFE	140	
Either line 139 or line 140, whichever applies		<u>32,681,114</u> F
Amount E divided by amount F. If negative, enter "0" . (enter in column 3 in Part 2M)		_____ % G

Part 2L – Excess IFE under subsection 18.2(2)

Variable A of IFE (amount A from Part 2A)	141	32,681,114
Total of the amounts determined under paragraph (h) of variable A of IFE (amount A from Part 1E)	142	
Total of the amounts determined under paragraph (j) of variable A of IFE (line 041 from Part 2A)	143	
Line 141 minus line 142 minus line 143. If negative, enter "0" .		<u>32,681,114</u> ▶ 32,681,114 A
Total of all amounts determined under subsection 18.2(2). Amount G in Part 2K multiplied by amount A in Part 2L. (enter on line 159 in Part 2O and in Schedule 1 of T2 return)		_____ B

Part 2M – Amounts determined under clause 95(2)(f.11)(ii)(D)

Use the following table to determine amounts that are not deductible under subclause 95(2)(f.11)(ii)(D)(I).

Row	1 Name of CFA	2 Amounts determined for variable A in the definition of IFE for the affiliate	3 Proportion determined under subsection 18.2(2) Amount G in Part 2K %	4 Denied amount under subclause 95(2)(f.11)(ii)(D)(I) Column 2 multiplied by column 3	5 The corporation's specified participating percentage under subsection 18.2(1) for the affiliate's tax year %	6 Corporation's share of the denied amount under subclause 95(2)(f.11)(ii)(D)(I) for the affiliate's tax year Column 4 multiplied by column 5
	144	145	146	147	148	149
1						
Total of column 6 (enter on line 161 in Part 2O)						150

Use the following table to determine amounts to be included under subclause 95(2)(f.11)(ii)(D)(II).

Row	1 Name of the CFA that is a member of the partnership	2 Amount determined under subclause 95(2)(f.11)(ii)(D)(II) in computing a CFA's FAPI	3 The corporation's specified participating percentage under subsection 18.2(1) for the affiliate's tax year %	4 The corporation's share of an amount included under subclause 95(2)(f.11)(ii)(D)(II) for the affiliate's tax year Column 2 multiplied by column 3
	151	152	153	154
1				
Total of column 4 (enter on line 162 in Part 2O)				155

Part 2N – Partnership IFE add-back under paragraph 12(1)(l.2)

Total of all amounts included under paragraph (h) of variable A of corporation's IFE (amount A from Part 1E)	156	
Ratio determined under subsection 18.2(2) (amount G from Part 2K)	157	%
Total add-back of partnership IFE under paragraph 12(1)(l.2) (line 156 multiplied by line 157) (enter on line 160 in Part 2O and in Schedule 1 of T2 return)	158	

Part 2O – RIFE under subsection 111(8)

Excess IFE under subsection 18.2(2) (amount B from Part 2L)	159	
Partnership IFE add-back under paragraph 12(1)(l.2) (line 158 from Part 2N)	160	
Amount determined under subclause 95(2)(f.11)(ii)(D)(I) (line 150 from Part 2M)	161	
Amount determined under subclause 95(2)(f.11)(ii)(D)(II) (line 155 from Part 2M)	162	
RIFE for the tax year. Total of lines 159 to 162 (enter in Schedule 4)		A

Charitable Donations and Gifts

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
---------------------------------------------------------------------	-----------------------------------	----------------------------------------------

- For use by corporations to claim any of the following:
 - the eligible amount of charitable donations to qualified donees
 - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
 - the eligible amount of gifts of certified cultural property
 - the eligible amount of gifts of certified ecologically sensitive land or
 - the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
 - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
 - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Charitable donations

Charity/Recipient	Amount (\$100 or more only)
Western Ottawa Community Resource Centre	200
Perley Health Foundation	200
Algonquin College	5,000
Heart & Stroke Foundation	200
St Peter Celestine's Parish	100
United Way	44,452
	Subtotal 50,152
	Add: Total donations of less than \$100 each
	Total donations in current tax year 50,152

Part 1 – Charitable donations

	Federal	Québec	Alberta
Charitable donations at the end of the previous tax year	87,104 1A	87,104	87,104
Charitable donations expired after five tax years* 239			
Charitable donations at the beginning of the current tax year (amount 1A minus line 239) 240	87,104	87,104	87,104
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary 250			
Total charitable donations made in the current year 210	50,152	50,152	50,152
(include this amount on line 112 of Schedule 1, Net Income (Loss) for Income Tax Purposes)			
Subtotal (line 250 plus line 210) 50,152 1B	50,152	50,152	50,152
Subtotal (line 240 plus amount 1B) 137,256 1C	137,256	137,256	137,256
Adjustment for an acquisition of control 255			
Total charitable donations available (amount 1C minus line 255) 137,256 1D	137,256	137,256	137,256
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2) 260	137,256	137,256	137,256
(enter this amount on line 311 of the T2 return)			
Charitable donations closing balance (amount 1D minus line 260) 280			
The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) 262			
Ontario community food program donation tax credit for farmers (amount on line 262 multiplied by 25%) 1			
Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).			
The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) 263			
Nova Scotia food bank tax credit for farmers (amount on line 263 multiplied by 25%) 2			
Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.			
The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016, and before January 1, 2027) 265			
British Columbia farmers' food donation tax credit (amount on line 265 multiplied by 25%) 3			
Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.			

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1 st prior year	2023-12-31	59,554	59,554	59,554
2 nd prior year	2022-12-31	27,550	27,550	27,550
3 rd prior year	2021-12-31			
4 th prior year	2020-12-31			
5 th prior year	2019-12-31			
6 th prior year*	2018-12-31			
7 th prior year	2017-12-31			
8 th prior year	2016-12-31			
9 th prior year	2015-12-31			
10 th prior year	2014-12-31			
11 th prior year	2013-12-31			
12 th prior year	2012-12-31			
13 th prior year	2011-12-31			
14 th prior year	2010-12-31			
15 th prior year	2009-12-31			
16 th prior year	2008-12-31			
17 th prior year	2007-12-31			
18 th prior year	2006-12-31			
19 th prior year	2005-12-31			
20 th prior year	2004-12-31			
21 st prior year*	2003-12-31			
Total (to line A)		87,104	87,104	87,104

* For federal and Alberta tax purposes, donations and gifts included on line 6th prior year expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line 6th prior year and donations and gifts that are included on line 21st prior year expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes (Note 1) multiplied by 75 %		1,684,544	2A
Taxable capital gains arising in respect of gifts of capital property included in Part 1 (Note 2)	225		
Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01)	227		
The amount of the recapture of capital cost allowance in respect of charitable donations	230		
Proceeds of disposition, less outlays and expenses (Note 2)	2B		
Capital cost (Note 2)	2C		
Amount 2B or 2C, whichever is less	235		
Amount on line 230 or 235, whichever is less			2D
Subtotal (add lines 225, 227, and amount 2D)			2E
Amount 2E multiplied by 25 %			2F
Subtotal (amount 2A plus amount 2F)		1,684,544	2G
Maximum allowable deduction for charitable donations (enter amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is the least)		137,256	2H

Note 1: For credit unions, this amount is before the deduction of bonus interest payments and payments pursuant to allocations in proportion to borrowing made by the credit union that is otherwise deductible under subsection 137(2).

Note 2: This amount must be prorated by the following calculation: eligible amount of the gift divided by the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

	Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year		3A	
Gifts of certified cultural property expired after five tax years*	439		
Gifts of certified cultural property at the beginning of the current tax year (amount 3A minus line 439)	440		
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450		
Total gifts of certified cultural property in the current year	410		
(include this amount on line 112 of Schedule 1)			
Subtotal (line 450 plus line 410)		3B	
Subtotal (line 440 plus amount 3B)		3C	
Adjustment for an acquisition of control	455		
Amount applied in the current year against taxable income	460		
(enter this amount on line 313 of the T2 return)			
Subtotal (line 455 plus line 460)		3D	
Gifts of certified cultural property closing balance (amount 3C minus amount 3D)	480		

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:	Federal	Québec	Alberta
1 st prior year	<u>2023-12-31</u>		
2 nd prior year	<u>2022-12-31</u>		
3 rd prior year	<u>2021-12-31</u>		
4 th prior year	<u>2020-12-31</u>		
5 th prior year	<u>2019-12-31</u>		
6 th prior year*	<u>2018-12-31</u>		
7 th prior year	<u>2017-12-31</u>		
8 th prior year	<u>2016-12-31</u>		
9 th prior year	<u>2015-12-31</u>		
10 th prior year	<u>2014-12-31</u>		
11 th prior year	<u>2013-12-31</u>		
12 th prior year	<u>2012-12-31</u>		
13 th prior year	<u>2011-12-31</u>		
14 th prior year	<u>2010-12-31</u>		
15 th prior year	<u>2009-12-31</u>		
16 th prior year	<u>2008-12-31</u>		
17 th prior year	<u>2007-12-31</u>		
18 th prior year	<u>2006-12-31</u>		
19 th prior year	<u>2005-12-31</u>		
20 th prior year	<u>2004-12-31</u>		
21 st prior year*	<u>2003-12-31</u>		
Total			

* For federal and Alberta tax purposes, donations and gifts included on line 6th prior year expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line 6th prior year and donations and gifts that are included on line 21st prior year expire automatically in the current tax year.

Part 4 – Gifts of certified ecologically sensitive land

	Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year	4A		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539		
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A minus line 539)	540		
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550		
Total current-year gifts of certified ecologically sensitive land (include this amount on line 112 of Schedule 1)	520		
Subtotal (line 550 plus line 520)	4B		
Subtotal (line 540 plus amount 4B)	4C		
Adjustment for an acquisition of control	555		
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560		
Subtotal (line 555 plus line 560)	4D		
Gifts of certified ecologically sensitive land closing balance (amount 4C minus amount 4D)	580		

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:	Federal	Québec	Alberta
1 st prior year	2023-12-31		
2 nd prior year	2022-12-31		
3 rd prior year	2021-12-31		
4 th prior year	2020-12-31		
5 th prior year	2019-12-31		
6 th prior year*	2018-12-31		
7 th prior year	2017-12-31		
8 th prior year	2016-12-31		
9 th prior year	2015-12-31		
10 th prior year	2014-12-31		
11 th prior year*	2013-12-31		
12 th prior year	2012-12-31		
13 th prior year	2011-12-31		
14 th prior year	2010-12-31		
15 th prior year	2009-12-31		
16 th prior year	2008-12-31		
17 th prior year	2007-12-31		
18 th prior year	2006-12-31		
19 th prior year	2005-12-31		
20 th prior year	2004-12-31		
21 st prior year*	2003-12-31		
Total			

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line 6th prior year and gifts that are included on line 11th prior year expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line 6th prior year and gifts that are included on line 21st prior year expire automatically in the current tax year.

Part 5 – Additional deduction for gifts of medicine

	Federal	Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year	5A		
Additional deduction for gifts of medicine expired after five tax years*	639		
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A minus line 639)	640		
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650		
Additional deduction for gifts of medicine made before March 22, 2017:			
Proceeds of disposition	602		
Cost of gifts of medicine made before March 22, 2017	601		
Subtotal (line 602 minus line 601)	5B		
Amount 5B multiplied by 50 %	5C		
Eligible amount of gifts	600		
Federal			
a _____ x $\left(\frac{b}{c} \right)$ = Additional deduction for gifts of medicine made before March 22, 2017	610		
Québec			
a _____ x $\left(\frac{b}{c} \right)$ = Additional deduction for gifts of medicine made before March 22, 2017			
Alberta			
a _____ x $\left(\frac{b}{c} \right)$ = Additional deduction for gifts of medicine made before March 22, 2017			
where:			
a is the lesser of line 601 and amount 5C			
b is the eligible amount of gifts (line 600)			
c is the proceeds of disposition (line 602)			
Subtotal (line 650 plus line 610)	5D		
Subtotal (line 640 plus amount 5D)	5E		
Adjustment for an acquisition of control	655		
Amount applied in the current year against taxable income	660		
(enter this amount on line 315 of the T2 return)			
Subtotal (line 655 plus line 660)	5F		
Additional deduction for gifts of medicine closing balance (amount 5E minus amount 5F) (Note 3)	680		

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Note 3: The amount at line 680 is not available for carryforward.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1 st prior year	2023-12-31			
2 nd prior year	2022-12-31			
3 rd prior year	2021-12-31			
4 th prior year	2020-12-31			
5 th prior year	2019-12-31			
6 th prior year*	2018-12-31			
7 th prior year	2017-12-31			
8 th prior year	2016-12-31			
9 th prior year	2015-12-31			
10 th prior year	2014-12-31			
11 th prior year	2013-12-31			
12 th prior year	2012-12-31			
13 th prior year	2011-12-31			
14 th prior year	2010-12-31			
15 th prior year	2009-12-31			
16 th prior year	2008-12-31			
17 th prior year	2007-12-31			
18 th prior year	2006-12-31			
19 th prior year	2005-12-31			
20 th prior year	2004-12-31			
21 st prior year*	2003-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line 6th prior year expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line 6th prior year and donations and gifts that are included on line 21st prior year expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
	Subtotal (line D plus line E)	F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1 st prior year	2023-12-31	
2 nd prior year	2022-12-31	
3 rd prior year	2021-12-31	
4 th prior year	2020-12-31	
5 th prior year	2019-12-31	
6 th prior year	2018-12-31	
7 th prior year	2017-12-31	
8 th prior year	2016-12-31	
9 th prior year	2015-12-31	
10 th prior year	2014-12-31	
11 th prior year	2013-12-31	
12 th prior year	2012-12-31	
13 th prior year	2011-12-31	
14 th prior year	2010-12-31	
15 th prior year	2009-12-31	
16 th prior year	2008-12-31	
17 th prior year	2007-12-31	
18 th prior year	2006-12-31	
19 th prior year	2005-12-31	
20 th prior year	2004-12-31	
21 st prior year*	2003-12-31	
Total		

* These gifts expired in the current year.

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
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- Corporations must use this schedule to report:
 - non-taxable dividends under section 83
 - deductible dividends under subsection 138(6)
 - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
 - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations (as defined in subsection 186(3)).
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
 - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
 - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, H.1, I, I.1, I.2 and L **only** if the payer corporation is **connected**.

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend)	A1	B Enter 1 if payer corporation is connected	C Business number of connected corporation	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD	E Non-taxable dividends under section 83
1	200		205	210	220	230
Total of column E (enter amount on line 402 of Schedule 1)						

Part 1 – Dividends received in the tax year (continued)

F	F1	G	H	H.1	I
Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1), (b), or (d) ¹		Eligible dividends included in column F	Total taxable dividends paid by the connected payer corporation (line 460 in Schedule 3 for the tax year in column D)	Total eligible dividends paid by the connected payer corporation (line 465 in Schedule 3 for the tax year in column D)	Dividend refund of the connected payer corporation (for tax year in column D) ²
240		242	250		260
1					
I.1	I.2	J	K	L	
Eligible dividend refund of the connected payer corporation from its eligible refundable dividend tax on hand (ERDTH) (amount CC from T2 return for the tax year in column D)	Additional non-eligible dividend refund of the connected payer corporation from its ERDTH (amount II from T2 return for the tax year in column D)	Part IV tax for eligible dividends. Dividends (from column G) multiplied by 38 1/3% ³	Part IV tax before deductions. Dividends (from column F) multiplied by 38 1/3% ⁴	Part IV tax before deductions on taxable dividends received from connected corporations ⁵	
		265	275	280	
1					
Total of column L (enter amount on line 2E in Part 2)					
Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B)					1A
Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B)					1B
Subtotal (amount 1A plus amount 1B, include this amount on line 320 of the T2 return)					1C
Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B)					1D
Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B)					1E
Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B)					1F
Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B)					1G
Subtotal (amount 1F plus amount 1G)					1H
Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B)					1I
Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B)					1J
Subtotal (amount 1I plus amount 1J)					1K
Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H minus amount 1K)					1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column K (and column J, if applicable). Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the **connected** payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to column I **divided** by column H **multiplied** by column F.

5 For the purpose of calculating your eligible refundable dividend tax on hand (ERDTH), Part IV tax on taxable dividends received from **connected** corporations (with a tax year starting after 2018) is equal to the sum of Part IV tax on eligible dividends and non-eligible dividends received from **connected** corporations to the extent that such dividends caused a dividend refund to those corporations from their ERDTH.

Part IV tax before deductions on taxable dividends received from **connected** corporations for purposes of column L is the sum of (i) and (ii), where

(i) Part IV tax on eligible dividends received from **connected** corporations is equal to amount CC of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 465 of the **connected** payer corporation, **multiplied** by column G; and

(ii) Part IV tax on non-eligible dividends received from **connected** corporations is equal to amount II of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 470 of the **connected** payer corporation, **multiplied** by the difference between columns F and G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1) 2A

Part IV tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) **320**

Subtotal (amount 2A minus line 320) 2B

Current-year non-capital loss claimed to reduce Part IV tax **330**

Non-capital losses from previous years claimed to reduce Part IV tax **335**

Current-year farm loss claimed to reduce Part IV tax **340**

Farm losses from previous years claimed to reduce Part IV tax **345**

Total losses applied against Part IV tax (total of lines 330 to 345) 2C

Amount 2C multiplied by 38 1 / 3 % 2D

Part IV tax payable (amount 2B minus amount 2D, if negative enter "0") **360**

(enter amount on line 712 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1) 2E

Amount 4A from Schedule 43 2F

Part IV tax payable on taxable dividends received from connected corporations
(amount 2E minus amount 2F, if negative enter "0") 2G

(enter at amount C on page 7 of the T2 return)

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1) 2H

Amount 4C from Schedule 43 2I

Part IV tax payable on taxable dividends received from non-connected corporations
(amount 2H minus amount 2I, if negative enter "0") 2J

(enter at amount D on page 7 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the recipient corporation with which you are connected, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	M Name of recipient corporation with which you are connected	N Business number	O Tax year-end of recipient corporation in which the dividends in column P were received YYYYMMDD	P Taxable dividends paid to recipient corporations with which you are connected	Q Eligible dividends included in column P
	400	410	420	430	440
1	Hydro Ottawa Holding Inc.		2024-12-31	5,760,000	
2					

5,760,000
(Total of column P) (Total of column Q)



Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations	450	
Eligible dividends included in line 450	455	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column P plus line 450)	460	5,760,000
Total eligible dividends paid in the tax year (total of column Q plus line 455)	465	
Total non-eligible taxable dividends paid in the tax year (line 460 minus line 465)	470	5,760,000
Complete this part to determine the following amounts in order to calculate the dividend refund.		
Line 465 multiplied by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)		3A
Line 470 multiplied by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)		2,208,000 3B

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)		5,760,000
Other dividends paid in the tax year (total of 510 to 540)		
Total dividends paid in the tax year	500	5,760,000
Dividends paid out of capital dividend account	510	
Capital gains dividends	520	
Dividends paid on shares described in subsection 129(1.2)	530	
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540	
Subtotal (total of lines 510 to 540)		▶ 4A
Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 minus amount 4A)		5,760,000 4B

Tax Calculation Supplementary – Corporations

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business Number [REDACTED]	Tax year-end Year Month Day 2024-12-31
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- Use this schedule if any of the following apply to your corporation during the tax year:
 - it had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only fill out columns A, B, and D in Part 1)
 - it is claiming provincial or territorial tax credits or rebates (see Part 2)
 - it has to pay taxes, other than income tax, for Newfoundland and Labrador or Ontario (see Part 2)
- All legislative references are to the Income Tax Regulations (the Regulations).
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Allocation of taxable income

100		Enter the regulation that applies (402 to 413).				
A Jurisdiction. (tick yes if your corporation had a permanent establishment in the jurisdiction during the tax year) Note 1		B Total salaries and wages paid in jurisdiction	C B multiplied by taxable income, divided by G	D Gross revenue attributable to jurisdiction	E D multiplied by taxable income, divided by H	F Allocation of taxable income (C + E x 1/2) Note 2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes <input type="checkbox"/>	103		143		
Newfoundland and Labrador Offshore	004 Yes <input type="checkbox"/>	104		144		
Prince Edward Island	005 Yes <input type="checkbox"/>	105		145		
Nova Scotia	007 Yes <input type="checkbox"/>	107		147		
Nova Scotia Offshore	008 Yes <input type="checkbox"/>	108		148		
New Brunswick	009 Yes <input type="checkbox"/>	109		149		
Quebec	011 Yes <input type="checkbox"/>	111		151		
Ontario	013 Yes <input type="checkbox"/>	113		153		
Manitoba	015 Yes <input type="checkbox"/>	115		155		
Saskatchewan	017 Yes <input type="checkbox"/>	117		157		
Alberta	019 Yes <input type="checkbox"/>	119		159		
British Columbia	021 Yes <input type="checkbox"/>	121		161		
Yukon	023 Yes <input type="checkbox"/>	123		163		
Northwest Territories	025 Yes <input type="checkbox"/>	125		165		
Nunavut	026 Yes <input type="checkbox"/>	126		166		
Outside Canada	027 Yes <input type="checkbox"/>	127		167		
Total		129	G	169	H	

Note 1: **Permanent establishment** is defined in subsection 400(2).
 Note 2: For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

- Notes:**
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
 2. If your corporation has provincial or territorial tax payable, fill out Part 2 on the following pages.
 3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
2,108,802		2,108,802	242,512
Ontario basic income tax (from Schedule 500) 270 242,512			
Ontario small business deduction (from Schedule 500) 402			
Subtotal (line 270 minus line 402) =			242,512 ▶ 242,512 5A
Ontario transitional tax debits and credits (from Schedule 506) 276			
Recapture of Ontario research and development tax credit (from Schedule 508) 277			
Subtotal (line 276 plus line 277) =			▶ 5B
Gross Ontario tax (amount 5A plus amount 5B)			242,512 5C
Ontario tax credit for manufacturing and processing (from Schedule 502) 406			
Ontario foreign tax credit (from Schedule 21) 408			
Ontario credit union tax reduction (from Schedule 500) 410			
Ontario political contributions tax credit (from Schedule 525) 415			
Ontario non-refundable tax credits (total of lines 406 to 415) =			▶ 5D
Subtotal (amount 5C minus amount 5D) (if negative, enter "0")			242,512 5E
Ontario research and development tax credit (from Schedule 508) 416 242,512			
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E minus line 416) (if negative, enter "0") 5F			
Ontario corporate minimum tax credit (from Schedule 510) 418			
Ontario community food program donation tax credit for farmers (from Schedule 2) 420			
Ontario corporate income tax payable (amount 5F minus the total of lines 418 and 420) (if negative, enter "0")			5G
Ontario corporate minimum tax (from Schedule 510) 278 1,075,798			
Ontario special additional tax on life insurance corporations (from Schedule 512) 280			
Subtotal (line 278 plus line 280) =			1,075,798 ▶ 1,075,798 5H
Total Ontario tax payable before refundable tax credits (amount 5G plus amount 5H)			1,075,798 5I
Ontario qualifying environmental trust tax credit 450			
Ontario co-operative education tax credit (from Schedule 550) 452 71,241			
Ontario computer animation and special effects tax credit (from Schedule 554) 456			
Ontario film and television tax credit (from Schedule 556) 458			
Ontario production services tax credit (from Schedule 558) 460			
Ontario interactive digital media tax credit (from Schedule 560) 462			
Ontario book publishing tax credit (from Schedule 564) 466			
Ontario innovation tax credit (from Schedule 566) 468			
Ontario business-research institute tax credit (from Schedule 568) 470			
Ontario regional opportunities investment tax credit (from Schedule 570) 472			
Ontario made manufacturing investment tax credit (from Schedule 572) 474			
Ontario refundable tax credits (total of lines 450 to 474) =			71,241 ▶ 71,241 5J
Net Ontario tax payable or refundable tax credit (amount 5I minus amount 5J)			290 1,004,557
(if a credit, enter amount in brackets). Include this amount on line 255.			

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits	255	1,004,557
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If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

Summary of Dispositions of Capital Property

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
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- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- All legislative references are to the Income Tax Act.
- Also use this schedule to make a designation under paragraph 111(4)(e) if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the T2 Corporation Income Tax Guide.
- If you need more space, attach additional schedules.

Designation under paragraph 111(4)(e)

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? **050** Yes No

If **yes**, attach a statement specifying which properties such a designation applies to.

In the various sections of this form:

- The abbreviation **FS** (for foreign source) is used to indicate the capital gain or loss arising from foreign property;
- The abbreviation **PA** (for passive asset) is used to indicate the capital gain or loss arising from the disposition of an asset other than an active asset of the corporation.

Part 1 – Shares

1 Number of shares	2 Name of corporation in which the shares were held	3 Class of shares	4 Date of acquisition YYYYMMDD	5 Proceeds of disposition	6 Adjusted cost base	7 Outlays and expenses from disposition	8 Gain (or loss) (column 5 minus columns 6 and 7)	A	
100	105	106	110	120	130	140	150	FS	PA
Totals									

Total adjustment under subsection 112(3) to all losses identified in column 8 **160**

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) **A**

Part 2 – Real estate (Do not include losses on depreciable property)

1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code	2 Date of acquisition YYYYMMDD	3 Proceeds of disposition	4 Adjusted cost base	5 Outlays and expenses from disposition	6 Gain (or loss) (column 3 minus columns 4 and 5)	A	
200	210	220	230	240	250	FS	PA
Totals							B

Part 3 – Bonds

1 Face value of bonds	2 Maturity date YYYYMMDD	3 Name of bond issuer	4 Date of acquisition YYYYMMDD	5 Proceeds of disposition	6 Adjusted cost base	7 Outlays and expenses from disposition	8 Gain (or loss) (column 5 minus columns 6 and 7)	A	
300	305	307	310	320	330	340	350	FS	PA
Totals									C

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property	2 Date of acquisition YYYYMMDD	3 Proceeds of disposition	4 Adjusted cost base	5 Outlays and expenses from disposition	6 Gain (or loss) (column 3 minus columns 4 and 5)	A	
400	410	420	430	440	450	FS	PA
Kilborn and Norice Land		286,779	54,119	15,613	217,047		
Totals		286,779	54,119	15,613	217,047	D	

Other property includes capital debts, debts in respect of the disposition of a personal-use property per subsection 50(2), amounts that arise from foreign currency transactions, and capital gains (losses) allocated from partnerships and trusts.

If you are a member of a partnership, include:

- under column 3 (line 420), any capital gain reported in boxes 151, 270, or 271 of the T5013 slips
- under column 4 (line 430), any capital loss reported in boxes 151, 270, or 271 of the T5013 slips

If you are a beneficiary of a trust, include under column 3 (line 420) the amount reported in box 21 of the T3 slips.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property	2 Date of acquisition YYYYMMDD	3 Proceeds of disposition	4 Adjusted cost base	5 Outlays and expenses from disposition	6 Gain only (column 3 minus columns 4 and 5; if negative, enter "0")	A	
500	510	520	530	540	550	FS	PA
Totals						E	

You **cannot** deduct losses on dispositions of personal-use property (other than listed personal property or a debt that is a personal-use property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property	2 Date of acquisition YYYYMMDD	3 Proceeds of disposition	4 Adjusted cost base	5 Outlays and expenses from disposition	6 Gain (or loss) (column 3 minus columns 4 and 5) <small>Note 1</small>	A	
600	610	620	630	640	650	FS	PA
Totals							

Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, Corporation Loss Continuity and Application) **655**

Net gains (or losses) from the disposition of listed personal property (total of column 6 minus line 655) **F**

Net listed personal property losses can only be applied against listed personal property gains.

Note 1: Do not include gains arising on the disposition of certain certified cultural property to a designated cultural institution. See subparagraph 39(1)(a)(i.1) for more information.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation	2 Shares, enter 1; debt, enter 2	3 Date of acquisition YYYYMMDD	4 Proceeds of disposition	5 Adjusted cost base	6 Outlays and expenses from disposition	7 Loss only (column 4 minus columns 5 and 6)	A	
900	905	910	920	930	940	950	FS	PA
Totals								

Allowable business investment losses (ABILs) Total of Column 7 _____ x 1/2 = **G**

Enter amount G on line 406 of Schedule 1, Net Income (Loss) for Income Tax Purposes.

Properties listed in Part 7 should **not** be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do not include amount F if it is a loss)	217,047	H		
Capital gains dividend received in the year	875		<input type="checkbox"/>	<input type="checkbox"/>
Capital gains reserve opening balance (from Part 1 of Schedule 13, Continuity of Reserves)	880			
Subtotal (amount H plus total of lines 875 and 880)	217,047	I		
Capital gains reserve closing balance (from Part 1 of Schedule 13, Continuity of Reserves)	885			
Capital gains or losses, excluding ABILs (amount I minus line 885)	890	217,047		

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8)	217,047	J		
Deduct the following amounts included in amount J, that are subject to the zero inclusion rate ^{Note 2} :				
Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under paragraphs 38(a.1)(i) and (iii)	895		<input type="checkbox"/>	<input type="checkbox"/>
Gain on the donation to a qualified donee of ecologically sensitive land under subsection 38(a.2) ^{Note 3}	896		<input type="checkbox"/>	<input type="checkbox"/>
Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under subsection 38(a.3)		a	<input type="checkbox"/>	<input type="checkbox"/>
Subtotal (line 895 plus line 896 plus line a)				K
Subtotal (amount J minus amount K)	217,047	L		
Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12):				
Exemption threshold at time of disposition	897			
The total of all capital gains from the actual disposition of the property	898			
Line 897 or line 898, whichever is less		M	<input type="checkbox"/>	<input type="checkbox"/>
Taxable capital gains under section 34.2 (line 275 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships)	x 2 = 899			
Subtotal (total of amounts L and M plus line 899)	217,047	N		
Allowable capital losses under section 34.2 (line 285 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships)	x 2 = 901			
Subtotal (amount N minus line 901)	217,047	O		
Portion of the capital gain that is subject to a 100% inclusion rate per 100(1) ^{Note 4}	x 2 = 902		<input type="checkbox"/>	<input type="checkbox"/>
Total capital gains or losses (amount O plus line 902)	217,047	P		

Taxable capital gains or total capital losses

Total capital losses (if amount P is negative, enter amount P; if amount P is positive, enter "0")		Q
Enter amount Q on line 210 of Schedule 4.		
Taxable capital gains (if amount P is positive, enter the result of amount P multiplied by 50.0000 %; if amount P is negative, enter "0")	217,047	108,524
Enter amount R on line 113 of Schedule 1.		

Note 2: When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only that part of the taxpayer's capital gain on disposition of the property that is attributable to the eligible amount of the donation. The amount of the gain attributable to any advantage (or benefit) received in respect of the donation is subject to the ordinary capital gains inclusion rate. See section 38.2 for more information.

Note 3: Do **not** include gains on donations of ecologically sensitive land to a private foundation.

Note 4: Do **not** include any portion of the capital gain that is subject to the 50% inclusion rate. Enter any such portion in Part 4. If you are a member of a partnership, include the amount reported in box 289 of the T5013 slip.

Aggregate Investment Income and Income Eligible for the Small Business Deduction

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
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- Use this schedule if you are a Canadian-controlled private corporation (CCPC) to calculate:
 - your aggregate investment income and foreign investment income, as defined in subsection 129(4), to determine the refundable portion of Part I tax, and your adjusted aggregate investment income, as defined in subsection 125(7), for the purpose of the business limit reduction
 - your **specified partnership income**, as defined in subsection 125(7), if you are a member (or **designated member**) of one or more partnerships, and
 - your income from an active business carried on in Canada eligible for the small business deduction including any **specified corporate income** as defined in subsection 125(7)
- Use this schedule if another CCPC is making an assignment of **business limit** under subsection 125(3.2) to you.
- Use this schedule if you are a member of a partnership to assign **specified partnership business limit** to a **designated member** under subsection 125(8).

Note: If you are an individual, a trust, or a corporation that is not a CCPC, **only** complete Table 1 (columns A1, B1, C1, G1, H1 and J1) and Table 3 to make this assignment. Individuals and trusts can attach the pages with these completed tables to their respective tax returns.
- The adjusted aggregate investment income, for the purpose of the business limit reduction, also applies to a tax year of a corporation that begins before 2019 and ends after 2018 under the following circumstances:
 - the corporation's preceding tax year was, because of a transaction or event or a series of transactions or events, shorter than it would have been in the absence of that transaction, event or series, and
 - one of the reasons for the transaction, event or series was to defer the application of subsections 125(5.1), (5.2) and (7) to the corporation
- All legislative references are to the federal Income Tax Act.
- For more information, see **Small Business Deduction** and **Refundable Portion of Part I Tax** in Guide T4012, T2 Corporation – Income Tax Guide.

Part 1 – Aggregate investment income

Aggregate investment income is all **world** source income.

Eligible portion of taxable capital gains for the year	002	108,524
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	012	
Net capital losses of previous years claimed on line 332 on the T2 return	022	
Subtotal (line 012 plus line 022)	▶	A
Line 002 minus amount A (if negative, enter "0")		108,524 B
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)	032	
Exempt income	042	
Amounts received from AgrilInvest Fund No. 2 that were included in computing the corporation's income for the year	052	
Taxable dividends deductible (total of column F on Schedule 3 minus related expenses)	062	
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	072	
Subtotal (add lines 042, 052, 062 and 072)	▶	C
Subtotal (line 032 minus amount C)	▶	D
Amount B plus amount D		108,524 E
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)	082	
Amount E minus line 082 (if negative, enter "0") (enter on line 440 of the T2 return)	092	108,524

Part 2 – Adjusted aggregate investment income

Eligible portion of taxable capital gains for the year (other than taxable capital gains from the disposition of an active asset ^{note 13})	705	
Eligible portion of allowable capital losses for the year (including allowable business investment losses) (other than allowable capital losses from the disposition of an active asset ^{note 13})	710	
Subtotal (line 705 minus line 710) (if negative, enter "0")		F
Total income from property ^{note 14}	715	
Exempt income	720	
Amounts received from AgrilInvest Fund No. 2 that were included in computing the corporation's income for the year	725	
Dividends from connected corporations	730	
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	735	
Subtotal (add lines 720, 725, 730 and 735)		G
Subtotal (line 715 minus amount G)		H
Amount F plus amount H		I
Total losses from property ^{note 14}	740	
Amount, if any, deducted under subsection 91(4) in computing the corporation's income for the year	741	
Adjusted aggregate investment income (amount I minus line 740, plus line 741) (if negative, enter "0")	745	

If this is your first tax year starting after 2018, complete the following portion.

Eligible portion of taxable capital gains for each tax year that ended in the preceding calendar year (other than taxable capital gains from the disposition of an active asset ^{note 13})		2A
Eligible portion of allowable capital losses for each tax year that ended in the preceding calendar year (including allowable business investment losses)(other than allowable capital losses from the disposition of an active asset ^{note 13})		2B
Subtotal (amount 2A minus amount 2B) (if negative, enter "0")		2C
Total income from property for each tax year that ended in the preceding calendar year ^{note 14}		2D
Exempt income for each tax year that ended in the preceding calendar year		2E
Amounts received from AgrilInvest Fund No. 2 that were included in computing the corporation's income for each tax year that ended in the preceding calendar year		2F
Dividends from connected corporations for each tax year that ended in the preceding calendar year		2G
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) for each tax year that ended in the preceding calendar year		2H
Subtotal (add amounts 2E, 2F, 2G and 2H)		2I
Subtotal (amount 2D minus amount 2I)		2J
Amount 2C plus amount 2J		2K
Total losses from property for each tax year that ended in the preceding calendar year ^{note 14}		2L
Amount, if any, deducted under subsection 91(4) in computing the corporation's income for each tax year that ended in the preceding calendar year	742	
Adjusted aggregate investment income (amount 2K minus amount 2L, plus line 742) (if negative, enter "0")	744	
(enter the total of line 744 and the adjusted aggregate investment income of all associated corporations on line 417 of the T2 return)		

Part 3 – Foreign investment income

Foreign investment income is all income from sources **outside Canada**.

Eligible portion of taxable capital gains for the year	001	_____
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	009	_____
Subtotal (line 001 minus line 009) (if negative, enter "0")			===== J
Total income from property from a source outside Canada (net of related expenses)	...	019	_____
Exempt income	029	_____
Taxable dividends deductible (total of column F on Schedule 3 minus related expenses)	049	_____
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	..	059	_____
Subtotal (add lines 029, 049, and 059)			===== ► K
Subtotal (line 019 minus amount K)			===== ► L
Amount J plus amount L			===== M
Total losses from property from a source outside Canada	069	_____
Amount M minus line 069 (if negative, enter "0") (enter on line 445 of the T2 return)	079	=====

Part 3A – Canadian and foreign investment income and adjusted aggregate investment income calculation

	A Canadian investment income	B Foreign investment income	C Adjusted aggregate investment income*
Eligible portion of the taxable capital gains for the year before taking into account the capital gains reserves (federal) of Schedule 13*	108,524		1.1
Eligible portion of capital gains reserves (addition/deduction)*, **			1.2
Taxable capital gains under section 34.2 (line 275 on Schedule 73)**			1.3
Eligible portion of the taxable capital gains for the year (add amounts 1.1, 1.2, and 1.3)	108,524		1
Eligible portion of allowable capital losses for the year (including allowable business investment losses)*			2.1
Net capital losses of previous years (line 332 on the T2 return)			2.2
Allowable capital losses under section 34.2 (line 285 of Schedule 73)**			2.3
Allowable capital losses for the year (add amounts 2.1, 2.2 and 2.3)			2
Amount 1 minus amount 2 (if negative, enter "0")	108,524		3
Taxable dividends			4.1
Rental property income (under regulation 1100(11))			4.2
Other property income*			4.3
Property income under section 34.2 (line 280 of Schedule 73)**			4.4
Total property income (add amounts 4.1, 4.2, 4.3 and 4.4)			4
Exempt income			5.1
Amounts received from AgrilInvest Fund No. 2 that were included in computing the corporation's income for the year			5.2
Taxable dividends deductible (total of column F on Schedule 3 minus related expenses)*			5.3
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)			5.4
Add amounts 5.1, 5.2, 5.3 and 5.4			5
Amount 4 minus amount 5			6
Amount 3 plus amount 6	108,524		7
Rental property losses (under regulation 1100(11))			8.1
Dividend losses			8.2
Other property losses*			8.3
Property losses under section 34.2 (line 280 of Schedule 73)**			8.4
Total property losses (add amounts 8.1, 8.2, 8.3 and 8.4)			8
Amount 7 minus amount 8 (if negative, enter "0")	108,524		9
Amount, if any, deducted under subsection 91(4) in computing the corporation's income for the year			10
Amount 7 minus amount 8 plus amount 10 (if negative, enter "0")			11

* To calculate the adjusted aggregate investment income under column C:

- On lines 1.1, 1.2, 1.3, 2.1 and 2.3, only capital gains and losses resulting from the disposition of property other than an active asset (as defined under subsection 125(7) ITA) are to be taken into account.
- On line 4.3, include amounts in respect of a life insurance policy that are included in computing the corporation's income for the year (even if those amounts are not included in the calculation of the corporation's investment income in column A and B) as well as the income from a specified foreign investment business.
- On line 5.3, only the dividends received from a connected corporation should be included.
- On line 8.3, include the loss from a specified foreign investment business.

For more information on the calculation of the adjusted aggregate investment income, consult notes 13 and 14 at the end of this form as well as the Help (F1).

** When an amount is entered on these lines in column B, it reduces the corresponding amount in column A. For more information, consult the Help (F1).

Net taxable dividends				Canadian	Foreign	Total
Taxable dividends deducted per Schedule 3						
Less: Expenses related to such dividends			A*			
Total expenses						
Net taxable dividends						

* Column A – Enter an “X” if the expense is related to a dividend received from a connected corporation.

Part 4 – Specified partnership income

Table 1 – Specified partnership income

A		A1	1A
Is the corporation a designated member of the partnership?		Partnership name	Partnership's account number
		200	
Yes	No		

B1	C1	D1	1D	2D	E1	F1
Total income (loss) of partnership from an active business	Your share of amount in column B1	Income of the corporation from providing (directly or indirectly) services or property to the partnership	Prorated amounts calculated under section 34.2 <small>note 1</small>	Expenses the corporation incurred to earn partnership income	Adjustments (column 1D minus column 2D)	Corporation's income (loss) in respect of the partnership <small>note 2</small> (add columns C1, D1 and E1)
300	310	311			315	320

Total 350

G1	H1	I1	J1	K1	L1	M1
Number of days in the partnership's fiscal period <small>note 15</small>	Prorated business limit <small>notes 2 and 3</small> (column C1 + column B1) × [\$ 500 000 × (column G1 + 365)] (if column C1 is negative, enter "0")	Specified partnership business limit assigned to you (from H2 in Table 2) <small>note 5</small>	Specified partnership business limit assigned by you from F3 in Table 3) <small>note 6</small>	Specified partnership business limit amount (column H1 plus column I1 minus column J1)	Column F1 minus column K1 (if negative, enter "0")	Lesser of columns F1 and K1 (if column F1 is negative, enter "0") <small>note 4</small>
325	330	335	336			340

Total 385 360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount **370**

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column F1) **380**

Subtotal (line 370 **plus** line 380) _____ N

Amount at line 385 or amount N, whichever is less **390**

Specified partnership income (line 360 **plus** line 390) **400**
(enter at amount R in Part 5)

Part 4 – Specified partnership income (continued)

Tables 2 and 3 are used to make an assignment of **specified partnership business limit** under subsection 125(8). A person that is a member of a partnership can make an assignment of **specified partnership business limit** under subsection 125(8) to a **designated member**.

If you are a CCPC that is a designated member and **receiving** specified partnership business limit from a person that is a member of the partnership, complete Table 2.

If you are a member of the partnership and are **assigning** specified partnership business limit to a designated member, complete Table 3.

Table 2 – A member is assigning to you specified partnership business limit under subsection 125(8)

A2	2A	B2
Partnership name	Partnership's account number	Name of the member
405		406

C2	D2	E2	F2	G2	H2
Business number of the member (if applicable)	Social insurance number of the member (if applicable)	Trust account number of the member (if applicable)	Tax year start of the member (YYYYMMDD)	Tax year-end of the member (YYYYMMDD)	Specified partnership business limit assigned to you by the member <small>note 7</small>
410	411	412	415	416	420

Table 3 – You are assigning to a designated member (CCPC) specified partnership business limit under subsection 125(8)

A3	3A	B3
Partnership name	Partnership's account number	Name of the designated member
425		426

C3	D3	E3	F3
Business number of the designated member	Tax year start of the designated member (YYYYMMDD)	Tax year-end of the designated member (YYYYMMDD)	Specified partnership business limit assigned by you to the designated member <small>note 8</small>
430	435	436	440

Part 5 – Partnership income not eligible for the small business deduction

Corporation's income from active businesses carried on in Canada as a member or designated member of a partnership (after deducting related expenses) – from line 350 in Part 4 (if the net amount is negative, enter "0" on line 450)	_____	O
Specified partnership loss (from line 380 in Part 4)	_____	P
		Subtotal (amount O plus amount P)	_____ Q
Specified partnership income (from line 400 in Part 4)	_____	R
Partnership income not eligible for the small business deduction (amount Q minus amount R)	450 _____	
(enter at amount Z in Part 6)			



Part 6 – Income eligible for the small business deduction

Net income for income tax purposes from line 300 of the T2 return	2,246,058	S	
Allowable business investment loss from line 406 of Schedule 1		T	
Subtotal (amount S plus amount T)	<u>2,246,058</u>		<u>2,246,058</u> U
Foreign business income after deducting related expenses ^{note 9}	500		
Taxable capital gains from line 113 of Schedule 1	108,524	V	
Net property income (line 032 ^{note 10} minus the total of lines 042, 052 and 082 ^{note 9} in Part 1)		W	
Personal services business income after deducting related expenses ^{note 9}		e1	
Other income after deducting related expenses ^{note 9}		e2	
Subtotal (amount e1 plus amount e2) ^{note 9}	520		
Subtotal (add line 500, amount V, amount W and line 520)	<u>108,524</u>		<u>108,524</u> X
Net amount (amount U minus amount X)			<u>2,137,534</u> Y
Partnership income not eligible for the small business deduction (line 450 in Part 5)		Z	
Partnership income allocated to your corporation under subsection 96(1.1)	530		
Income referred to in clause 125(1)(a)(i)(C)	540		
Income referred to in clause 125(1)(a)(i)(B) (from line 615 in Part 7)		AA	
Subtotal (add amount Z, line 530, line 540 and amount AA)			BB
Specified corporate income (from line 625 in Part 7)			CC
Income eligible for the small business deduction (amount Y minus amount BB, plus amount CC)			<u>2,137,534</u> DD

(enter amount DD on line 400 of the T2 return - if negative, enter "0")

Part 7 – Specified corporate income and assignment under subsection 125(3.2)

1EE Name of the corporation	EE Business number of the corporation	FF Income described under clause 125(1)(a)(i)(B) received from the corporation identified in column EE ^{note 11}	GG Business limit assigned from the corporation identified in column EE ^{note 12}
1	600	610	620
Total		615	625

See the privacy notice on your return.

Notes

1. Do **not** include expenses that were deducted in computing the income of the corporation in column D1.
In general, amounts included under subsections 34.2(2) and 34.2(3) or claimed under subsection 34.2(4) are deemed to have the **same character** and be in the **same proportions** as the partnership income they relate to. For example, if a corporation receives \$100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of \$40,000 of active business income, \$30,000 of income from property, and \$30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct only the portion of the following amounts that are characterized as **active business income** in accordance with subsection 34.2(5):
Add:
 - the ASPA under subsection 34.2(2) (column 4 of Schedule 73)
 - the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73)**Deduct:**
 - the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73)
 - the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73)
2. When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is **not** netted against the partnership's income when calculating the prorated business limit (column H1). Enter on line 380 the total of all losses from column F1.
3. If you are a **designated member** of the partnership, enter "0".
4. You must enter "0" if the partnership provides services or property to either:
 - (A) a private corporation (directly or indirectly in any manner whatever) in the year, if:
 - you (or one of your shareholders) or a person that does **not** deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and
 - it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
 - persons (other than the private corporation) that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
 - partnerships with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest, or
 - (B) a particular partnership (directly or indirectly in any manner whatever) in the year, if:
 - you (or one of your shareholders) do **not** deal at arm's length with the particular partnership or a person that holds a direct or indirect interest in the particular partnership, and
 - it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
 - persons that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
 - partnerships (other than the particular partnership) with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest.
5. If you are a CCPC that is a **designated member** receiving an assignment of **specified partnership business limit**, complete Table 2 to determine the amounts to enter in Table 1 column I1.
6. If you are a **member** of the partnership and you are assigning **specified partnership business limit**, complete Table 3 to determine the amounts to enter in Table 1 column J1.
7. Add the amounts in column H2 that are for the same partnership and enter it in Table 1 column I1, in the row of the applicable partnership.
8. Add the amounts in column F3 that are for the same partnership and enter it in Table 1 column J1, in the row of the applicable partnership. This amount **cannot** be higher than the amount of prorated business limit you would otherwise be entitled to in Table 1 column H1 for that partnership.
9. If negative, enter amount in brackets, and **add** instead of subtracting.
10. Net of related expenses.
11. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts, each of which is your income from an active business for the year from providing services or property to a private corporation (directly or indirectly, in any manner whatever) if
 - (A) at any time in the year, you (or one of your shareholders) or a person that does not deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and
 - (B) it is not the case that all or substantially all of your income for the year from an active business is from providing services or property to
 - (I) persons (other than the private corporation) with which you deal at arm's length, or
 - (II) partnerships with which you deal at arm's length, other than a partnership in which a person that does not deal at arm's length with you holds a direct or indirect interest.

Do **not** include specified farming or fishing income. If the conditions described in subsection 125(10) are met, do not include income from an associated corporation.
12. The amount of business limit that a CCPC can assign to you cannot be greater than the amount in column FF that is from providing services or property **directly** to that CCPC. If there is an amount included in column FF that is deductible by that CCPC in respect of the amount of its income referred to in clause 125(1)(a)(i)(A) or (B) for its tax year, you need to deduct it from column FF for the purpose of determining the amount that can be assigned to you.

Notes (continued)

13. Active asset, of a particular corporation at any time, means property that is:
- (A) used at that time principally in an active business carried on primarily in Canada by the particular corporation or by a Canadian-controlled private corporation that is related to the particular corporation,
 - (B) a share of the capital stock of another corporation if, at that time,
 - the other corporation is connected with the particular corporation (within the meaning assigned by subsection 186(4) on the assumption that the other corporation is at that time a payer corporation within the meaning of that subsection), and
 - the share would be a qualified small business corporation share (as defined in subsection 110.6(1)) if:
 - the references in that definition to an "individual" were references to the particular corporation, and
 - that definition were read without reference to "the individual's spouse or common-law partner", or
 - (C) an interest in a partnership, if:
 - at that time, the fair market value of the particular corporation's interest in the partnership is equal to or greater than 10% of the total fair market value of all interests in the partnership,
 - throughout the 24-month period ending before that time, more than 50% of the fair market value of the property of the partnership was attributable to property described in this paragraph or in paragraph (A) or (B), and
 - at that time, all or substantially all of the fair market value of the property of the partnership was attributable to property described in this paragraph or in paragraph (A) or (B).
14. Income or loss from property of a particular corporation, for the purposes of calculating the corporation's adjusted aggregate investment income, includes income or loss from a specified investment business, as well as all amounts in respect of a life insurance policy that are included in computing the corporation's income for the year (even if those amounts were not included in the computation of the corporation's aggregate investment income in Part 1).
15. The maximum number of days that can be entered in column G1 for a partnership's fiscal period is 365, it is not adjusted for a leap year.

Capital Cost Allowance (CCA)

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
-----------------------------------------------------------------	-------------------------------	----------------------------------------------

For more information, see the section called "Capital Cost Allowance" in Guide T4012, *T2 Corporation – Income Tax*.

Unless otherwise stated, all legislative references are to the federal *Income Tax Act*.

Is the corporation electing under subsection 1101(5q) of the *Income Tax Regulations*? **101** Yes No

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the tax year with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? **105** Yes No

If you answered **yes**, fill out Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your corporation) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 2.

1 Name of EPOP	2 Identification number Note 1	3 Percentage assigned under the agreement
1. [REDACTED] 110	115	120
Total		125

Immediate expensing limit allocated to the corporation (see **Note 2**) **125**

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your corporation in column 3. If the total of column 3 is more than 100%, enter "0".

Part 2 – CCA calculation

1 Class number	Description	2 Undepreciated capital cost (UCC) at the beginning of the year	3 Cost of acquisitions during the year (new property must be available for use)	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP)	5 Adjustments and transfers	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	8 Proceeds of dispositions
Note 3			Note 4	Note 5	Note 6	Note 7	Note 8	Note 9
200		201	203	232	205	221	222	207
1. 1		128,931,246						8,216
2. 1b		77,606,912	593,068		-8,372			1,457
3. 2	Dist equip pre 88	36,385,516						0
4. 3	buildings pre 88	4,335,934						7,828
5. 8		6,060,779	969,736		-16,060			0
6. 10		4,383,825	1,643,685					113,090
7. 12			4,929,897		17,929			0
8. 42		3,700,302	84,908		8,718			0
9. 43.2	SOLAR ASSETS	25,299	742,215					0
10. 45		120						0
11. 47		665,887,271	85,930,151		-160,760			0
12. 50		326,283	4,185,796		-3,510			2,856
13. 14.1	Pre 2017 ECE	7,500,207						0
14. 14.1	Land Rights / Line connection	47,701,008	509,607					0
15. 17	Parking Lot	1,977,598	31,796					0
16. 43.1			1,186,557					0
Totals		984,822,300	100,807,416		-162,055			133,447

1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4)	10 UCC (column 2 plus column 3 plus or minus column 5)	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4)	12 Immediate expensing	13 Cost of acquisitions on remainder of Class (column 3 minus column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56	15 Remaining UCC (column 10 minus column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 plus column 6 minus column 13 plus column 14 minus column 7) (if negative, enter "0")
			Note 10	Note 11	Note 12		Note 13		
		234		236	238		225		
1. 1			128,923,030					128,923,030	
2. 1b			78,190,151		593,068	593,068		78,190,151	1,457

1 Class number	Description	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4)	10 UCC (column 2 plus column 3 plus or minus column 5 minus column 8) Note 10	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) Note 11	12 Immediate expensing Note 12	13 Cost of acquisitions on remainder of Class (column 3 minus column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIIP) or properties included in Classes 54 to 56 Note 13	15 Remaining UCC (column 10 minus column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIIP and property included in Classes 54 to 56 (column 8 plus column 6 minus column 13 plus column 14 minus column 7) (if negative, enter "0")
		234		236	238		225		
3.	2 Dist equip pre 88		36,385,516					36,385,516	
4.	3 buildings pre 88		4,328,106					4,328,106	
5.	8		7,014,455			969,736	969,736	7,014,455	
6.	10		5,914,420			1,643,685	1,643,685	5,914,420	113,090
7.	12		4,947,826			4,929,897	4,929,897	4,947,826	
8.	42		3,793,928			84,908	84,908	3,793,928	
9.	43.2 SOLAR ASSETS		767,514			742,215	742,215	767,514	
10.	45		120					120	
11.	47		751,656,662			85,930,151	85,926,091	751,656,662	
12.	50		4,505,713			4,185,796	4,185,796	4,505,713	2,856
13.	14.1 Pre 2017 ECE		7,500,207					7,500,207	
14.	14.1 Land Rights / Line connection		48,210,615			509,607	509,607	48,210,615	
15.	17 Parking Lot		2,009,394			31,796	31,796	2,009,394	
16.	43.1		1,186,557			1,186,557	1,186,557	1,186,557	
Totals			1,085,334,214			100,807,416	100,803,356	1,085,334,214	117,403

Part 2 – CCA calculation (continued)

1 Class number	Description	17 Net capital cost additions of AIP and property included in Classes 54 to 56 acquired during the year (column 14 minus column 16) (if negative, enter "0")	18 UCC adjustment for AIP and property included in Classes 54 to 56 acquired during the year (column 17 multiplied by the relevant factor) Note 14	19 UCC adjustment for property acquired during the year other than AIP and property included in Classes 54 to 56 (0.5 multiplied by the result of column 13 minus column 14 minus column 6 plus column 7 minus column 8) (if negative, enter "0") Note 15	20 CCA rate % Note 16	21 Recapture of CCA Note 17	22 Terminal loss Note 18	23 CCA (for declining balance method, the result of column 15 plus column 18 minus column 19, multiplied by column 20, or a lower amount, plus column 12) Note 19	24 UCC at the end of the year (column 10 minus column 23)
				224	212	213	215	217	220
1.	1				4	0	0	5,156,921	123,766,109
2.	1b	591,611			6	0	0	4,691,409	73,498,742
3.	2	Dist equip pre 88			6	0	0	2,183,131	34,202,385
4.	3	buildings pre 88			5	0	0	216,405	4,111,701
5.	8	969,736			20	0	0	1,402,891	5,611,564
6.	10	1,530,595			30	0	0	1,774,326	4,140,094
7.	12	4,929,897			100	0	0	4,947,826	
8.	42	84,908			12	0	0	455,271	3,338,657
9.	43.2	SOLAR ASSETS	742,215	371,108	50	0	0	569,311	198,203
10.	45				45	0	0	54	66
11.	47	85,926,091			8	0	0	60,132,533	691,524,129
12.	50	4,182,940			55	0	0	2,478,142	2,027,571
13.	14.1	Pre 2017 ECE			5	0	0	525,014	6,975,193
14.	14.1	Land Rights / Line connection	509,607		5	0	0	2,410,531	45,800,084
15.	17	Parking Lot	31,796		8	0	0	160,752	1,848,642
16.	43.1		1,186,557	1,779,836	30	0	0	889,918	296,639
	Totals	100,685,953	2,150,944					87,994,435	997,339,779

Enter the total of column 21 on line 107 of Form T2 SCH 1, *Net Income (Loss) for Income Tax Purposes*.

Enter the total of column 22 on line 404 of Form T2 SCH 1.

Enter the total of column 23 on line 403 of Form T2 SCH 1.

- Note 3: If a class number has not been provided in Schedule II of the *Income Tax Regulations* for a particular class of property, use the subsection provided in Regulation 1101.
- Note 4: Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, *General Discussion of Capital Cost Allowance*, for exceptions to the 50% rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6). See Guide T4012 for more information about the cost of acquisitions during the year.
- Note 5: A DIEP reported in column 4 is a property acquired after April 18, 2021, by a corporation that was a Canadian-controlled private corporation (CCPC) throughout the year, which became available for use in the tax year (before 2024) and was designated as such on or before the day that is 12 months after the filing-due date for the tax year to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the year in which it becomes available for use. See subsection 1104(3.1) of the *Regulations* for more information.
- Note 6: Enter in column 5, "Adjustments and transfers," amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See Guide T4012 for other examples of adjustments and transfers to include in column 5. Also include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.
- Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Part 2 – CCA calculation (continued)

Note 8: Include all amounts you have repaid during the year for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the undepreciated capital cost, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter "0". The only amounts incurred before April 19, 2021, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) of the Regulations are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the tax year (total of column 12) should not exceed the lesser of:

- Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:
 - \$1.5 million, if you are not associated with any other EPOP in the tax year
 - amount from line 125, if you are associated in the tax year with one or more EPOPs
 - nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the tax year with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
 - the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent tax years ending in a calendar year, if you have two or more tax years ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
 - any amount allocated by the minister under subsection 1104(3.4) of the Regulations

The immediate expensing limit has to be prorated if your tax year is less than 365 days. You cannot carry forward any unused amount of the immediate expensing limit.

- UCC of the DIEP: total of column 11

You have to maintain the CCPC status throughout the relevant tax year in order to claim the immediate expensing.

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.

Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.

Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.

See Guide T4012 for more information.

Note 14: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use respectively before 2024 or in 2024 are:

- 2 1/3 or 1 1/2 for property in Classes 43.1, 54, and 56
- 1 1/2 or 7/8 for property in Class 55
- 1 or 1/2 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 19 for additional information) and
- 0.5 or 0 for all other property that is an AIIP

If the tax year begins in 2023 and ends in 2024, the relevant factor is determined under paragraph 1100(2.01)(a) of the Regulations.

Part 2 – CCA calculation (continued)

Note 15: The UCC adjustment for property acquired during the year (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56). For special rules and exceptions, see Income Tax Folio S3-F4-C1, *General Discussion of Capital Cost Allowance*.

Note 16: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter "N/A". Then enter the amount you are claiming in column 23.

Note 17: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 18: If no property is left in the class at the end of the tax year and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 19: If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4012 for more information.

For property in Class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year.

For AIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: if the capital cost of the property was incurred before 2024, the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction), and in any other case, the amount for the year calculated in accordance with Schedule III of the Regulations
- Class 14: the lesser of 150% (if the property becomes available for use in the year and before 2024) or 125% (if the property becomes available for use in the year and after 2023) of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% (if the property is acquired in the year and before 2024) or 125% (if the property is acquired in the year and after 2023) of an amount calculated on the basis of a rate per cord, board foot, or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% (for property acquired in the year and before 2024) or 33 1/3% (in any other case) of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP provisions also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to an industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the *Income Tax Regulations* for more details.

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation Hydro Ottawa Limited/Hydro Ottawa Limitee	Business Number [REDACTED]	Tax year end Year Month Day 2024-12-31
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- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	100	200	300	400	500	550	600	650	700
	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
1.	Hydro Ottawa Holding Inc./Societe	[REDACTED]	[REDACTED]	1					
2.	Energy Ottawa Inc./Energie Ottawa	[REDACTED]	[REDACTED]	3					
3.	Telecom Ottawa Holding Inc. / Soc	[REDACTED]	[REDACTED]	3					
4.	PowerTrail Inc.	[REDACTED]	[REDACTED]	3					
5.	Moose Creek Energy Inc.	[REDACTED]	[REDACTED]	3					
6.	Chaudiere Hydro Inc. Hydro Chaud	[REDACTED]	[REDACTED]	3					
7.	Chaudiere Water Power Inc/Energi	[REDACTED]	[REDACTED]	3					
8.	2425932 ONTARIO INC.	[REDACTED]	[REDACTED]	3					
9.	CHAUDIERE HYDRO NORTH INC.	[REDACTED]	[REDACTED]	3					
10.	EO GENERATION GP INC.	[REDACTED]	[REDACTED]	3					
11.	THE GANANOQUE WATER POWER	[REDACTED]	[REDACTED]	3					
12.	EONY GENERATION HOLDING INC	US	[REDACTED]	3					
13.	EONY GENERATION LIMITED	US	[REDACTED]	3					
14.	9927891 CANADA INC.	[REDACTED]	[REDACTED]	3					
15.	ENERGY OTTAWA CABLE TESTING	[REDACTED]	[REDACTED]	3					
16.	HULL ENERGY GP INC.	[REDACTED]	[REDACTED]	3					
17.	Smart City Lighting Inc.	[REDACTED]	[REDACTED]	3					
18.	Envari Holding Inc.	[REDACTED]	[REDACTED]	3					
19.	Envari Energy Solutions Inc.	[REDACTED]	[REDACTED]	3					
20.	CHAUDIERE SERVICES INC./SERVI	[REDACTED]	[REDACTED]	3					
21.	CHAUDIERE FINANCIAL INC./FINA	[REDACTED]	[REDACTED]	3					
22.	2725163 Ontario Inc.	[REDACTED]	[REDACTED]	3					
23.	Hiboo Networks Inc.	[REDACTED]	[REDACTED]	3					
24.	Hydro Ottawa Capital Corporation	[REDACTED]	[REDACTED]	1					
25.	Hydro Ottawa Engergy Services Inc	[REDACTED]	[REDACTED]	3					
26.	Hydro Ottawa District Engergy Inc.	[REDACTED]	[REDACTED]	3					
27.	Hydro Ottawa Civic Community Util	[REDACTED]	[REDACTED]	3					
28.	Envari Construction Holding Inc	[REDACTED]	[REDACTED]	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

Continuity of Reserves

Name of corporation Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year end Year Month Day 2024-12-31
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- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation Income Tax Guide.

Part 1 – Capital gains reserves

Description of property	Balance at the beginning of the year \$	Transfer on an amalgamation or the wind-up of a subsidiary \$	Add \$	Deduct \$	Balance at the end of the year \$
001	002	003			004
1					
Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, Summary of Dispositions of Capital Property. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description	Balance at the beginning of the year \$	Transfer on an amalgamation or the wind-up of a subsidiary \$	Add \$	Deduct \$	Balance at the end of the year \$
	110	115			120
Reserve for doubtful debts <input checked="" type="checkbox"/>	4,140,541		962,347		5,102,888
Reserve for undelivered goods and services not rendered <input type="checkbox"/>	2,635,000			155,000	2,480,000
Reserve for prepaid rent <input type="checkbox"/>					
Reserve for refundable containers <input type="checkbox"/>					
Reserve for unpaid amounts <input type="checkbox"/>					
Other tax reserves <input type="checkbox"/>					
Totals	6,775,541		962,347	155,000	7,582,888

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, Net Income (Loss) for Income Tax Purposes, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1					
Reserves from Part 2 of Schedule 13	4,140,541		962,347		5,102,888
Totals	4,140,541		962,347		5,102,888

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.

The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Deferred Income Plans

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year end Year Month Day 2024-12-31
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- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

Type of plan (see note 1)	Amount of contribution \$ (see note 2)	Registration number (RPP, RSUBP, PRPP, and DPSP only)	Name of EPSP trust	Address of EPSP trust	T4PS slip(s) (see note 3)
100	200	300	400	500	600
1	6,621,000	345983			

Note 1

Enter the applicable code number:

- 1 – RPP
- 2 – RSUBP
- 3 – DPSP
- 4 – EPSP
- 5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	6,621,000	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	6,621,000	B
Deductible amount for contributions to deferred income plans (amount A minus amount B) (if negative, enter "0")		C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year must file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

- 1 – Associated for purposes of allocating the business limit (unless association code 5 applies)
- 2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation
- 3 – Non-CCPC that is a **third corporation**
- 4 – Associated non-CCPC
- 5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

Column 4: Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

Column 5: Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A does not exceed \$500,000.

Allocating the business limit

Date filed (do not use this area) **025** Year Month Day

Enter the calendar year the agreement applies to **050** Year
2024

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? **075** Yes No

	1 Name of associated corporations	2 Business number of associated corporations	3 Association code	4 Business limit for the year before the allocation \$	5 Percentage of the business limit %	6 Business limit allocated* \$
	100	200	300		350	400
1	Hydro Ottawa Limited/Hydro Ottawa Limitee		1	500,000	100.0000	500,000
2	Hydro Ottawa Holding Inc./Societe De [REDACTED]		1	500,000		
3	Energy Ottawa Inc./Energie Ottawa Inc.		1	500,000		
4	Telecom Ottawa Holding Inc. / Societe De [REDACTED]		1	500,000		
5	PowerTrail Inc.		1	500,000		
6	Moose Creek Energy Inc.		1	500,000		
7	Chaudiere Hydro Inc. Hydro Chaudiere Inc.		1	500,000		
8	Chaudiere Water Power Inc/Energie Hydrauliqu		1	500,000		
9	2425932 ONTARIO INC.		1	500,000		
10	CHAUDIERE HYDRO NORTH INC.		1	500,000		
11	EO GENERATION GP INC.		1	500,000		
12	THE GANANOQUE WATER POWER COMPANY		1	500,000		
13	EONY GENERATION HOLDING INC.		1	500,000		
14	EONY GENERATION LIMITED		1	500,000		
15	9927891 CANADA INC.		1	500,000		
16	ENERGY OTTAWA CABLE TESTING SERVICES [REDACTED]		1	500,000		
17	HULL ENERGY GP INC.		1	500,000		
18	Smart City Lighting Inc.		1	500,000		

	1 Name of associated corporations	2 Business number of associated corporations	3 Association code	4 Business limit for the year before the allocation \$	5 Percentage of the business limit %	6 Business limit allocated* \$
	100	200	300		350	400
19	Envari Holding Inc.		1	500,000		
20	Envari Energy Solutions Inc.		1	500,000		
21	CHAUDIÈRE SERVICES INC./SERVICES		1	500,000		
22	CHAUDIÈRE FINANCIAL INC./FINANCIÈRE DE L		1	500,000		
23	2725163 Ontario Inc.		1	500,000		
24	Hiboo Networks Inc.		1	500,000		
25	Hydro Ottawa Capital Corporation		1	500,000		
26	Hydro Ottawa Energy Services Inc.		1	500,000		
27	Hydro Ottawa District Energy Inc.		1	500,000		
28	Hydro Ottawa Civic Community Utility Inc.		1	500,000		
29	Envari Construction Holding Inc		1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula $0.225\% \times (C - \$10,000,000)$. Another factor is the "adjusted aggregate investment income" from lines 744 and 745 of Schedule 7, Aggregate Investment Income and Income Eligible for the Small Business Deduction. Details of these formulas and variable C are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the lesser of: the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year.

PAYMENTS TO NON-RESIDENTS

Name of corporation Hydro Ottawa Limited/Hydro Ottawa Limitee	Business Number [REDACTED]	Tax year end Year Month Day 2024-12-31
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- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than \$100, you do not have to complete the information for that payee.

	Name (list each payee separately)	Address	Payment code (see note 1)	Amount \$
	100	200	300	400
1	Doble Engineering Company	123 Fleton Street Malborough MA US	02	31,730

Note 1: Enter the applicable payment code in column 300:

1 – Royalties	6 – Interest	
2 – Rents	7 – Dividends	
3 – Management fees/commissions	8 – Film payments: – motion picture film, or – a film or video tape for use in connection with television	
4 – Technical assistance fees	9 – Other services	
5 – Research and development fees		

Investment Tax Credit – Corporations

General information

- Use this schedule:
 - to calculate an investment tax credit (ITC) earned during the tax year
 - to claim a deduction against Part I tax payable
 - to claim a refund of credit earned during the current tax year
 - to claim a carryforward of credit from previous tax years
 - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1)
 - to request a credit carryback to one or more previous years
 - if you are subject to a recapture of ITC
- Unless otherwise stated, all legislative references are to the Income Tax Act or, where appropriate, the Income Tax Regulations.
- Certain ITCs are eligible for a three-year carryback (if not deductible in the year earned) and are also eligible for a twenty-year carryforward. This does not apply to the clean economy ITCs, which are refundable tax credits.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
 - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
 - You can no longer claim the ITC for the qualified resource property expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
 - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
 - pre-production mining expenditures (Part 18)
 - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
 - apprenticeship job creation expenditures (Parts 19 to 21)
 - child care spaces expenditures (Part 22)
 - You can no longer claim the ITC for the child care spaces expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
- Investments or expenditures for the clean economy, described in sections 127.44, 127.45, 127.48, and 127.49, that earn an ITC are investments in (Part 24):
 - carbon capture, utilization, or storage (CCUS) projects, for qualifying expenditures made after 2021
 - clean technology property that is acquired and becomes available for use after March 27, 2023
 - eligible clean hydrogen property that is acquired and becomes available for use after March 27, 2023
 - clean technology manufacturing (CTM) property that is used in qualifying manufacturing and processing activities or the extraction and processing of certain critical minerals and that is acquired and becomes available for use after 2023
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see **Investment Tax Credits** in Guide T4012, T2 Corporation – Income Tax Guide.
- For more information on SR&ED, see Guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired. For rules related to capital cost for the CCUS ITC, clean technology ITC, clean hydrogen ITC, and clean technology manufacturing ITC, see, respectively, subsections 127.44(9), 127.45(5), 127.48(10), and 127.49(5).
- An ITC deducted in a tax year for a depreciable property reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use (AFU)** before a claim for an ITC can be made. See subsections 127(11.2), 127.45(4), 127.48(5), 127.49(4), and 248(19) for more information. The AFU rules do not apply to claims for the CCUS ITC.
- Expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than one year after the claimant's income tax return is due for the tax year in which it incurred the expenditures. A claimant that does not meet this reporting deadline will not be able to file Schedule 508, Ontario Research and Development Tax Credit, and Schedule 566, Ontario innovation Tax Credit.
- Expenditures for an apprenticeship ITC must be identified by the claimant on Schedule 31 no later than one year after the claimant's income tax return is due for the tax year in which it incurred the expenditures.
- The claimant must identify the clean economy ITC on Schedule 31 no later than one year after the claimant's income tax return is due for the tax year it is entitled to claim the credit for (for the CCUS ITC and the clean hydrogen ITC, the claimant must identify the ITC by the later of this date and December 31, 2025).

Detailed information (continued)

- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms). See section 127.47 for rules that apply to partnerships for the clean economy ITCs generally. For more information on partnership allocations for the CCUS ITC, clean technology ITC, clean hydrogen ITC, and clean technology manufacturing ITC, see, respectively, subsections 127.44(11), 127.45(8), 127.48(12), and 127.49(8).
- For certain purposes, Canada includes the **exclusive economic zone of Canada** as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone. For the clean technology ITC, Canada includes the exclusive economic zone of Canada only for property that is described in subparagraph (d)(v) or (xiv) of Class 43.1 in Schedule II of the Regulations.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Certain qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures and percentages

Investments	Specified percentage
Qualified property and qualified resource property (Part 5)	
Qualified property acquired primarily for use in Atlantic Canada	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15 % rate.	35 %
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada	15 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
Clean economy ITCs (Part 24)	
For work performed after November 27, 2023, to qualify for the investment tax credit rates indicated below, an incentive claimant must elect (in prescribed form) to meet certain labour requirements – prevailing wage requirements and apprenticeship requirements. Otherwise, the credit rate will be reduced by 10 percentage points. The incentive claimant must also attest (in prescribed form) to have met these requirements. The labour requirements do not apply to the clean technology manufacturing ITC.	
CCUS	
If you incurred qualified carbon capture expenditures to capture carbon directly from ambient air:	
after 2021 and before 2031	60%
after 2030 and before 2041	30%
If you incurred qualified carbon capture expenditures to capture carbon other than directly from ambient air:	
after 2021 and before 2031	50%
after 2030 and before 2041	25%
If you incurred qualified expenditures for carbon transportation, use, or storage:	
after 2021 and before 2031	37.5%
after 2030 and before 2041	18.75%
Clean technology	
If you acquired clean technology property after March 27, 2023, and it becomes available for use:	
before 2034	30%
in 2034	15%
Clean hydrogen	
If you acquired an eligible clean hydrogen property after March 27, 2023, and it becomes available for use:	
before 2034	depending on the carbon intensity tier 40%, 25% or 15%
in 2034	depending on the carbon intensity tier 20%, 12.5%, or 7.5%
For clean ammonia equipment or certain other equipment used solely in connection with clean ammonia equipment, the rate is 15% if the equipment becomes available for use before 2034 and 7.5% if it becomes available for use in 2034.	
Clean technology manufacturing	
If you acquired CTM property after 2023 and it becomes available for use:	
before 2032	30%
in 2032	20%
in 2033	10%
in 2034	5%

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
-----------------------------------------------------------------	-------------------------------	----------------------------------------------

Part 2A – Determination of a qualifying corporation

This section does not apply to the clean economy investment tax credits.

Is the corporation a qualifying corporation? **101** Yes No

Enter your taxable income for the previous tax year¹ (prior to any loss carrybacks applied) **390**

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10.

¹ If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 2B – Determination of an excluded corporation – SR&ED

Is the qualifying corporation an excluded corporation as defined under subsection 127.1(2)? **650** Yes No

Only a 40% refund will be available to a qualifying corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

- one or more persons exempt from Part I tax under section 149
- Her Majesty in right of a province, a Canadian municipality, or any other public authority
- any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** Yes No

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED² x 80 % = **103**

Enter on line 350 of Part 8.

² Enter only contributions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property from the current tax year

Capital cost allowance class number	Description of investment	Date available for use	Location used in Atlantic Canada (province)	Amount of investment
105	110	115	120	125
Total of investments for qualified property				4A



Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year		5A
Credit deemed as a remittance of co-op corporations	210	
Credit expired	215	
Subtotal (line 210 plus line 215)	▶	5B
ITC at the beginning of the tax year (amount 5A minus amount 5B)	220	
Credit transferred on an amalgamation or the wind-up of a subsidiary	230	
ITC from repayment of assistance	235	
Qualified property (amount 4A) x 10 % =	240	
Credit allocated from a partnership	250	
Subtotal (total of lines 230 to 250)	▶	5C
Total credit available (line 220 plus amount 5C)		5D
Credit deducted from Part I tax	260	
Credit carried back to previous years (amount 6A)		5E
Credit transferred to offset Part VII tax liability	280	
Subtotal (total of line 260, amount 5E, and line 280)	▶	5F
Credit balance before refund (amount 5D minus amount 5F)		5G
Refund of credit claimed on investments from qualified property (from Part 7)	310	
ITC closing balance of investments from qualified property and qualified resource property (amount 5G minus line 310)	320	

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903
Total of lines 901 to 903 Enter at amount 5E.					6A

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property

Current-year ITCs (line 240 plus line 250 in Part 5)		7A
Credit balance before refund (from amount 5G)		7B
Refund (40 % of amount 7A or 7B, whichever is less)		7C

Enter amount 7C or a lesser amount on line 310 in Part 5 (also include in line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Qualified SR&ED expenditures (line 559 on Form T661)	6,409,252		
Contributions to agricultural organizations for SR&ED			
Deduct:			
Government assistance, non-government assistance, or contract payment			
Subtotal			
x	80 %		
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.) ³		+	
Qualified SR&ED expenditures (line 559 on Form T661 plus line 103 in Part 3) ³	6,409,252	▶	350 6,409,252
Repayments made in the year (from line 560 on Form T661)			370
Total qualified SR&ED expenditures (line 350 plus line 370)			380 6,409,252

³ If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? **385** Yes No

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete line 398.

If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

Enter your taxable capital employed in Canada for the previous tax year **minus** \$10 million. **398**

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation

\$ 40,000,000 minus line 398 in Part 9	10A	
Amount 10A divided by \$ 40,000,000		10B
Expenditure limit for the stand-alone corporation (\$ 3,000,000 multiplied by amount 10B) ⁴		10C

For an associated corporation

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49⁴ **400**

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount 10C or line 400 x $\frac{\text{Number of days in the tax year}}{365}$ = **366** = 10D

Your SR&ED expenditure limit for the year (enter amount 10C, line 400, or amount 10D, whichever applies) **410**

⁴ Amount 10C or line 400 cannot be more than \$3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Qualified SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less ⁵	420	x	35 %	=	11A
Line 350 minus line 410 (if negative, enter "0")	430	6,409,252	x	15 %	= 961,388 11B

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8)

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC ⁶	460	x	35 %	=	11C
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred before 2015	480	x	20 %	=	11D
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred after 2014	490	x	15 %	=	11E
Subtotal (total of amounts 11C to 11E)					11F
Current-year SR&ED ITC (total of amounts 11A, 11B, and 11F; enter on line 540 in Part 12)					<u>961,388</u> 11G

⁵ For corporations that are not CCPCs, enter "0" for amount 11A.

⁶ If you were a CCPC, this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year					1,123,459 12A
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
Subtotal (line 510 plus line 515)					12B
ITC at the beginning of the tax year (amount 12A minus amount 12B)	520				<u>1,123,459</u>
Credit transferred on an amalgamation or the wind-up of a subsidiary	530				
Total current-year credit (from amount 11G)	540	961,388			
Credit allocated from a partnership	550				
Subtotal (total of lines 530 to 550)					961,388 12C
Total credit available (line 520 plus amount 12C)					<u>2,084,847</u> 12D
Credit deducted from Part I tax	560	310,005			
Credit carried back to previous years (amount 13A)					12E
Credit transferred to offset Part VII tax liability	580				
Subtotal (total of line 560, amount 12E, and line 580)					310,005 12F
Credit balance before refund (amount 12D minus amount 12F)					<u>1,774,842</u> 12G
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)	610				
ITC closing balance on SR&ED (amount 12G minus line 610)	620				<u>1,774,842</u>

Part 13 – Request for carryback of credit from SR&ED expenditures

Year	Month	Day

1st previous tax year	Credit to be applied	911	_____
2nd previous tax year	Credit to be applied	912	_____
3rd previous tax year	Credit to be applied	913	_____
		Total of lines 911 to 913		===== 13A
		Enter at amount 12E.		=====

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part if you are a qualifying corporation as determined on line 101 in Part 2A.⁷

Current-year ITC (lines 540 plus 550 in Part 12 minus amount 11F)	_____	14A
Refundable credits (amount 14A or amount 12G, whichever is less)	_____	14B
Amount 14B or amount 11A, whichever is less	_____	14C
Net amount (amount 14B minus amount 14C; if negative, enter "0")	=====	14D
Amount 14D multiplied by 40 %	=====	14E
Amount 14C	_____	14F
Refund of ITC (amount 14E plus amount 14F – enter this, or a lesser amount, on line 610 in Part 12)	=====	14G

Include the total of line 310 in Part 5 and line 610 in Part 12 in line 780 of the T2 return.

⁷ If you are also an excluded corporation, as determined in Part 2B, amount 14B must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount 14G.

Part 15 – Refund of ITC for CCPCs that are neither qualifying nor excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying corporation as determined on line 101 in Part 2A or an excluded corporation as determined on line 650 in Part 2B.

Credit balance before refund (amount 12G)	_____	1,774,842	15A
Refund of ITC (amount 15A or amount 11A, whichever is less)	=====		15B

Enter amount 15B, or a lesser amount, on line 610 in Part 12 and also include it in line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less
Subtotal		
Enter at amount 17A.		16A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount 16B.

A	B	C	D	E	F
Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	Amount determined by the formula (A x B) – C	ITC earned by the transferee for the qualified expenditures that were transferred 750	Amount from column D or E, whichever is less
Subtotal (total of column F)					
Enter at amount 17B.					16B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760**
Enter at amount 17C.



Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount 16A	_____	17A
Recaptured ITC from calculation 2, amount 16B	_____	17B
Recaptured ITC from calculation 3, line 760 in Part 16	_____	17C
Total recapture of SR&ED investment tax credit (total of amounts 17A to 17C)	=====	17D
Enter at amount 25A in Part 25.			

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year	_____	18A
Credit deemed as a remittance of co-op corporations	841 _____	
Credit expired	845 _____	
	Subtotal (line 841 plus line 845)	=====	18B
ITC at the beginning of the tax year (amount 18A minus amount 18B)	850 _____	
Credit transferred on an amalgamation or the wind-up of a subsidiary	860 _____	
Total credit available (line 850 plus line 860)	=====	18C
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year	885 _____	
ITC closing balance from pre-production mining expenditures (amount 18C minus line 885)	890 _____	

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.)

611 Yes No

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice)	B Name of eligible trade	C Eligible salary and wages ⁸	D Column C x 10 %	E Lesser of column D or \$ 2,000
	601	602	603	604	605
1.	[REDACTED]	Power Line Technician	50,404	5,040	2,000
2.	[REDACTED]	Power Line Technician	45,467	4,547	2,000
3.	[REDACTED]	Power Line Technician	41,873	4,187	2,000
4.	[REDACTED]	Power Line Technician	46,719	4,672	2,000
5.	[REDACTED]	Power Line Technician	48,003	4,800	2,000
6.	[REDACTED]	Power Line Technician	44,263	4,426	2,000
7.	[REDACTED]	Power Line Technician	83,158	8,316	2,000
8.	[REDACTED]	Power Line Technician	78,650	7,865	2,000
9.	[REDACTED]	Power Line Technician	84,256	8,426	2,000
10.	[REDACTED]	Power Line Technician	47,860	4,786	2,000
Total current-year credit (total of column E) Enter on line 640 in Part 20.					<u>20,000</u> 19A

⁸ Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year	12,000	20A
Credit deemed as a remittance of co-op corporations	612	
Credit expired after 20 tax years	615	
Subtotal (line 612 plus line 615)	<u> </u>	20B
ITC at the beginning of the tax year (amount 20A minus amount 20B)	625	<u>12,000</u>
Credit transferred on an amalgamation or the wind-up of a subsidiary	630	
ITC from repayment of assistance	635	
Total current-year credit (amount 19A)	640	20,000
Credit allocated from a partnership	655	
Subtotal (total of lines 630 to 655)	<u>20,000</u>	<u>20,000</u> 20C
Total credit available (line 625 plus amount 20C)		<u>32,000</u> 20D
Credit deducted from Part I tax	660	32,000
Credit carried back to previous years (amount 21A)		20E
Subtotal (line 660 plus amount 20E)	<u>32,000</u>	<u>32,000</u> 20F
ITC closing balance from apprenticeship job creation expenditures (amount 20D minus amount 20F)	690	<u> </u>

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

Year	Month	Day

1st previous tax year
2nd previous tax year
3rd previous tax year

..... Credit to be applied **931** _____
..... Credit to be applied **932** _____
..... Credit to be applied **933** _____

Total of lines 931 to 933 _____ 21A
Enter at amount 20E.

Child Care Spaces

Part 22 – Account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year		22A
Credit deemed as a remittance of co-op corporations	765	
Credit expired after 20 tax years	770	
Subtotal (line 765 plus line 770)	765	22B
ITC at the beginning of the tax year (amount 22A minus amount 22B)	775	
Credit transferred on an amalgamation or the wind-up of a subsidiary	777	
Credit allocated from a partnership	782	
Subtotal (line 777 plus line 782)	777	22C
Total credit available (line 775 plus amount 22C)		22D
Credit deducted from Part I tax	785	
ITC closing balance from child care spaces expenditures (amount 22D minus line 785)	790	

Recapture – Child Care Spaces

Part 23 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be added to the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property, one of the following situations takes place:

- the new child care space is no longer available
- property that was an eligible expenditure for the child care space is
 - disposed of or leased to a lessee
 - converted to another use

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) **792**

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC **795**

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property **797**

Amount from line 795 or line 797, whichever is less 23A

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 22. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799**

Total recapture of child care spaces investment tax credit (total of line 792, amount 23A, and line 799) 23B

Enter at amount 25B in Part 25.

Summary of Investment Tax Credits

Part 24 – Clean economy ITCs

Clean hydrogen ITC	140	
Clean technology ITC (from Schedule 75)	155	
Clean technology manufacturing ITC (from Schedule 76)	170	
Carbon capture, utilization, and storage ITC (from Schedule 78)	200	
Clean economy ITCs (total of lines 140 to 200)		24A
Include the total on line 780 of the T2 return.		

Part 25 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount 17D)		25A
Recaptured child care spaces ITC (amount 23B)		25B
Recaptured or recovered clean hydrogen ITC		25C
Recaptured clean technology ITC (from Schedule 75)		25D
Recaptured clean technology manufacturing ITC (from Schedule 76)		25E
Total recapture of investment tax credit (total of amounts 25A to 25E)		25F
Enter on line 602 of the T2 return.		

Part 26 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5)		26A
ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12)	310,005	26B
ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18)		26C
ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20)	32,000	26D
ITC from child care space expenditures deducted from Part I tax (line 785 in Part 22)		26E
Total ITC deducted from Part I tax (total of amounts 26A to 26E)		26F
Enter on line 652 of the T2 return.		

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
20,000	20,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2023-12-31	12,000		12,000	
2022-12-31				
2021-12-31				
2020-12-31				
2019-12-31				
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
Total	12,000		12,000	

B+C+D+G **Total ITC utilized** **32,000**

* The ITC end of year includes the amount of ITC expired from the 20th preceding year. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
961,388				961,388

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2023-12-31	384,277			384,277
2022-12-31				
2021-12-31				
2020-12-31	494,149		64,972	429,177
2019-12-31	245,033		245,033	
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
Total	1,123,459		310,005	813,454

B+C+D+G **Total ITC utilized** 310,005

* The ITC end of year includes the amount of ITC expired from the 20th preceding year. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Taxable Capital Employed in Canada – Large Corporations

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
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- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than \$10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than \$10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101		
Capital stock (or members' contributions if incorporated without share capital)	103	167,081,000	
Retained earnings	104	330,426,000	
Contributed surplus	105		
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	620,094,000	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (add lines 101 to 112)		<u>1,117,601,000</u>	<u>1,117,601,000</u> A

Note:

Line 112 is determined by the formula $(A - B) \times C/D$ (as per paragraph 181.2(3)(g)) where:

- A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
 - a) those lines applied to partnerships in the same manner that they apply to corporations, and
 - b) those amounts were computed without reference to amounts owing by the partnership
 - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
 - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.
- B is the partnership's deferred unrealized foreign exchange losses at the end of the period,
- C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and
- D is the partnership's income or loss for the period.

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 1,109,271,000 x $\frac{\text{Taxable income earned in Canada } \mathbf{610}}{\text{Taxable income } 2,108,802}$ = **Taxable capital employed in Canada** $\mathbf{690}$ 1,109,271,000

- Notes:**
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
 2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of \$1,000.
 3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . **701** _____

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada **711** _____

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **712** _____

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) **713** _____

Total deductions (**add** lines 711, 712, and 713) _____ **E**

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") **790** _____

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) _____ **F**

Deduct: 10,000,000 **G**

Excess (amount F **minus** amount G) (if negative, enter "0") _____ **H**

Calculation for purposes of the small business deduction (amount H x 0.225%) _____ **I**

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount
Notes Payable		542,519,000 00
Customer credit balances	+	14,541,000 00
Customer deposits	+	63,034,000 00
	+	
	+	
	+	
	Total	620,094,000 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula $1+2*3$ will not result in the same thing as the formula $1+3*2$.

Shareholder Information

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
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- All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.
- Provide only one number (business number, partnership account number, social insurance number or trust number) per shareholder.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Business number or partnership account number (9 digits, 2 letters, and 4 digits. If not registered, enter "NR")	Social insurance number (9 digits)	Trust number (T followed by 8 digits)	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	Hydro Ottawa Capital Corporation	[REDACTED]			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

General Rate Income Pool (GRIP) Calculation

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
-----------------------------------------------------------------	-------------------------------	----------------------------------------------

On: 2024-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- Credit unions are **not** required to complete this schedule.
- All legislative references are to the federal Income Tax Act and Income Tax Regulations.
- When an eligible dividend was paid in the tax year or there was a change in the GRIP balance, file a completed copy of this schedule with your T2 Corporation Income Tax Return. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? Yes No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006?
Enter the date and go directly to question 4
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? Yes No
If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? Yes No
5. Corporations that become a CCPC or a DIC Yes No
If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation Yes No
If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? Yes No
If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? Yes No
If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? Yes No
If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? Yes No
If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? Yes No
If the answer to question 11 is yes, complete Part 3.

Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year	100	234,498,956	
Taxable income for the year (DICs enter "0")*	110	2,108,802	
Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least*	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140	108,524	
Subtotal (line 130 plus line 140)		108,524	▶ 108,524 A
Income taxable at the general corporate rate (line 110 minus amount A) (if negative enter "0")	150	2,000,278	
After-tax income (line 150 multiplied by 0.72 (the general rate factor for the tax year))	190	1,440,200	
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (line 200 plus line 210)			▶ B
Becoming a CCPC (amount W5 in Part 4)	220		
Post-amalgamation (total of amount E4 in Part 3 and amount W5 in Part 4)	230		
Post-wind-up (total of amount E4 in Part 3 and amount W5 in Part 4)	240		
Subtotal (add lines 220, 230, and 240)	290		▶
Subtotal (add lines 100, 190, 290, and amount B)		235,939,156	C
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year (If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.)	310		
Subtotal (line 300 minus line 310)			▶ D
GRIP before adjustment for specified future tax consequences (amount C minus amount D) (amount can be negative)	490	235,939,156	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount L3 in Part 2)	560		
GRIP at the end of the tax year (line 490 minus line 560)	590	235,939,156	

Enter this amount on line 160 of Schedule 55, Part III.1 Tax on Excessive Eligible Dividend Designations.

* For lines 110, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (for example, flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2023-12-31

Taxable income before specified future tax consequences
 from the current tax year A1

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410,
 or 428 of the T2 return,
 whichever is the least B1

Aggregate investment income
 (line 440 of the T2 return) C1

Subtotal (amount B1 plus amount C1) D1

Subtotal (amount A1 minus amount D1) (if negative, enter "0") E1

Future tax consequences that occur for the current year
 Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences F1

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410,
 or 428 of the T2 return,
 whichever is the least G1

Aggregate investment income
 (line 440 of the T2 return) H1

Subtotal (amount G1 plus amount H1) I1

Subtotal (amount F1 minus amount I1) (if negative, enter "0") J1

Subtotal (amount E1 minus amount J1) (if negative, enter "0") K1

GRIP adjustment for specified future tax consequences to the first previous tax year

(amount K1 multiplied by 0.72) **500**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Second previous tax year 2022-12-31

Taxable income before specified future tax consequences from the current tax year A2

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least B2

Aggregate investment income (line 440 of the T2 return) C2

Subtotal (amount B2 **plus** amount C2) D2

Subtotal (amount A2 **minus** amount D2) (if negative, enter "0") E2

Future tax consequences that occur for the current year					
Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences F2

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least G2

Aggregate investment income (line 440 of the T2 return) H2

Subtotal (amount G2 **plus** amount H2) I2

Subtotal (amount F2 **minus** amount I2) (if negative, enter "0") J2

Subtotal (amount E2 **minus** amount J2) (if negative, enter "0") K2

GRIP adjustment for specified future tax consequences to the second previous tax year

(amount K2 **multiplied** by 0.72) **520**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2021-12-31

Taxable income before specified future tax consequences from the current tax year 5,925,748 A3

Enter the following amounts before specified future tax consequences from the current tax year:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least B3

Aggregate investment income (line 440 of the T2 return) 826,786 C3

Subtotal (amount B3 plus amount C3) 826,786 ▶ 826,786 D3

Subtotal (amount A3 minus amount D3) (if negative, enter "0") 5,098,962 ▶ 5,098,962 E3

Future tax consequences that occur for the current year					
Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences F3

Enter the following amounts after specified future tax consequences:

Amount on line 400, 405, 410, or 428 of the T2 return, whichever is the least G3

Aggregate investment income (line 440 of the T2 return) H3

Subtotal (amount G3 plus amount H3) I3

Subtotal (amount F3 minus amount I3) (if negative, enter "0") J3

Subtotal (amount E3 minus amount J3) (if negative, enter "0") K3

GRIP adjustment for specified future tax consequences to the third previous tax year

(amount K3 multiplied by 0.72) **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:

(add lines 500, 520, and 540) (if negative, enter "0") 540 L3

Enter amount L3 on line 560

**Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up
(predecessor or subsidiary was a CCPC or a DIC in its last tax year)**

nb. 1 Post amalgamation . . . Post wind-up

- Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.
- Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.
- Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.
- In the calculation below, **corporation** means a predecessor or a subsidiary. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year	_____	A4
Eligible dividends paid by the corporation in its last tax year	_____	B4
Excessive eligible dividend designations made by the corporation in its last tax year	_____	C4
	Subtotal (amount B4 minus amount C4)	=====	D4
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year) (amount A4 minus amount D4)	=====	E4

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the E4 amounts. Enter this total amount on:
– line 230 for post-amalgamation; or
– line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC Post amalgamation Post wind-up

- Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year, or when a corporation has become a CCPC since the end of its previous tax year. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.
- Calculate the GRIP addition of a successor corporation following an amalgamation at the end of its first tax year.
- Calculate the GRIP addition of a parent corporation upon wind-up at the end of the tax year that ends immediately after the tax year in which the parent has received the assets of the subsidiary.
- Calculate the GRIP addition of a corporation that became a CCPC since the end of its previous tax year.
- In the calculation below, **corporation** means a predecessor or a subsidiary, or a corporation that became a CCPC since the end of its previous tax year. Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year A5

The corporation's money on hand immediately before the end of its previous/last tax year B5

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses C5
 Net capital losses D5
 Farm losses E5
 Restricted farm losses F5
 Limited partnership losses G5

Subtotal (add amounts C5 to G5) H5

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses I5
 Net capital losses J5
 Farm losses K5
 Restricted farm losses L5
 Limited partnership losses M5

Subtotal (add amounts I5 to M5) N5

Unused and unexpired losses at the end of the corporation's previous/last tax year (amount H5 minus amount N5) O5

Subtotal (add amounts A5, B5, and O5) P5

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year Q5

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year R5

All the corporation's reserves deducted in its previous/last tax year S5

The corporation's capital dividend account immediately before the end of its previous/last tax year T5

The corporation's low rate income pool immediately before the end of its previous/last tax year U5

Subtotal (add amounts Q5 to U5) V5

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (amount P5 minus amount V5) (if negative, enter "0") W5

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the W5 amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
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- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year not included in Schedule 3	_____	
Taxable dividends paid in the tax year included in Schedule 3	5,760,000	
Total taxable dividends paid in the tax year	100 5,760,000	
Total eligible dividends paid in the tax year		150 _____
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")		160 235,939,156
Excessive eligible dividend designation (line 150 minus line 160)		_____ A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *		180 _____
Subtotal (amount A minus line 180)		_____ B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B multiplied by 20 %)		190 _____

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year not included in Schedule 3	_____	
Taxable dividends paid in the tax year included in Schedule 3	_____	
Total taxable dividends paid in the tax year	200 _____	
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)		_____ C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *		280 _____
Subtotal (amount C minus line 280)		_____ D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D multiplied by 20 %)		290 _____

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.



Request for Capital Dividend Account Balance Verification

- If you are a private corporation, use this schedule to summarize the components making up your capital dividend account (CDA) balance as of the date you specify below, on line 003.
- Mail one completed copy of this schedule, separately from any other return to:
Prince Edward Island Tax Centre
275 Pope Road
Summerside PE C1N 6A2
- Unless otherwise stated, all legislative references are to the current version of the Income Tax Act. Since CDA balance components can span several years, the current references in the Act may not apply to older components of your CDA balance. In these cases, see the version of the Act that applies for that particular year.
- For specific details about calculating the CDA balance, see the applicable legislation in the Act.
- All references to paragraphs in subsection 89(1) of the Act are under the definition of **capital dividend account**.
- If you are paying out a capital dividend from your CDA, you must first file Form T2054, Election for a Capital Dividend Under Subsection 83(2). If a capital dividend paid out under this election exceeds the balance of the CDA at the time the dividend becomes payable, you may have to pay Part III tax on the excess dividend (see section 184 of the Act).

Part 1 – Identification

002 Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee		001 Business number [REDACTED]	
Address		City	Province Postal code
019 Name of contact person Bettina Yau			
024 Name of firm		022 Telephone number (613) 738-5499	023 Extension
Capital dividend account balance as of		003 Year Month Day 2024-12-31	
Please check yes for only one of the following two questions:			
Is this a balance verification request? Check yes only if this request does not relate to a Form T2054, mentioned at line 005		004 <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	
(if yes , then the date on line 003 should be the last tax year-end, included in the CDA balance)			
Is this request related to the requirements of subsection 89(1) for Form T2054?		005 <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	
(if yes , then the date on line 003 should be the earlier of the date the dividend became payable, or the first day on which any part of the dividend was paid)			

Part 2A – CDA components (except for eligible capital property) – Summary lines for predecessor corporations
(for amounts after July 13, 1990) ^{1 and 2}

Only complete this part of the schedule if you have any predecessor balances to report. If you do **not** have any predecessor balances, proceed to **Part 2B**.

1	2	3	4	5	6	7	8
Predecessor business number	Amalgamation date (YYYY/MM/DD)	The non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and non-deductible portion of capital losses per paragraph 89(1)(a)	Capital dividends received per paragraph 89(1)(b)	Net proceeds of a life insurance policy per paragraph 89(1)(d)	Non-taxable portion of capital gains from a trust before September 16, 2016 per paragraph 89(1)(f)	Capital dividends from a trust per paragraph 89(1)(g)	Capital dividends payable per subsection 83(2)
3 080	082	4 084	5 086	088	6 090	6 092	094
1.							
Totals:							

If you need more space, attach additional schedules.

- 1 For eligible capital property, see parts 3 and 7.
- 2 The CDA balance may be reduced to nil immediately before the dates referred to in those provisions if you were:
 - a private corporation under non-resident control that became Canadian controlled as per subsection 89(1.1)
 - or a tax-exempt corporation that became taxable as per subsection 89(1.2), the CDA balance may be reduced to nil immediately before the dates referred to in those provisions
- 3 For amalgamations and wind-ups after **July 13, 1990**, carry over the amounts of all the CDA components of each predecessor corporation into the calculation of the CDA components of the successor or parent corporation. A negative balance in a component of a CDA of a predecessor corporation must be included in the CDA of the successor or parent corporation. Include a separate CDA calculation on a separate schedule for each predecessor corporation that **does not match** with the amounts in My Business Account.
- 4 Along with applicable losses, include the non-deductible portion of a business investment loss here. Show losses as a negative.
- 5 May be adjusted by an excessive dividend election under subsection 184(3). Exclude a dividend that subsection 83(2.1) applies to.
- 6 The amounts that can be added to the CDA of the corporation in a particular tax year, in respect of amounts received by the corporation, from a trust and that are attributable to capital gains realized by the trust or to dividends received and distributed by a trust, can only be determined after the end of the taxation year of the trust in which the capital gains were realized or the dividends were received and distributed by it.

Part 2B – CDA components (except for eligible capital property) – Detail lines for filing corporation ^{7 and 8}

	1	2	3	4	5	6	7
	Tax year-end or relevant date (YYYY/MM/DD)	The non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and non-deductible portion of capital losses per paragraph 89(1)(a)	Capital dividends received per paragraph 89(1)(b)	Net proceeds of a life insurance policy per paragraph 89(1)(d)	Non-taxable portion of capital gains from a trust before September 16, 2016 per paragraph 89(1)(f)	Capital dividends from a trust per paragraph 89(1)(g)	Capital dividends payable per subsection 83(2)
	9	10	11		12	12	
	100	110	120	130	140	150	160
1.	2006-12-31	225,385.00					
2.	2007-12-31						
3.	2008-12-31						
4.	2009-12-31						
5.	2010-12-31	1,259,282.00					
6.	2011-12-31						
7.	2012-12-31						
8.	2013-12-31						
9.	2014-12-31						
10.	2021-12-31	826,786.00					
	2024-12-31	108,524.00					
	Totals:	2,419,977.00					

If you need more space, attach additional schedules.

7 For eligible capital property, see parts 3 and 7.

8 The CDA balance may be reduced to nil immediately before the dates referred to in those provisions if you were:

- a private corporation under non-resident control that became Canadian controlled as per subsection 89(1.1),
- or a tax-exempt corporation that became taxable as per subsection 89(1.2), the CDA balance may be reduced to nil immediately before the dates referred to in those provisions.

9 Include as many tax years as required. Start your list with the tax year that began after the corporation last became a private corporation and that ended after 1971. End your list on the CDA balance date shown on line 003. If you are completing this schedule before your tax year-end, enter the relevant date of the activity.

10 Along with applicable losses, include the non-deductible portion of a business investment loss here. Show losses as a negative.

11 May be adjusted by an excessive dividend election under subsection 184(3). Exclude a dividend that subsection 83(2.1) applies to.

12 The amounts that can be added to the CDA of the corporation in a particular tax year, in respect of amounts received by the corporation, from a trust and that are attributable to capital gains realized by the trust or to dividends received and distributed by a trust, can only be determined after the end of the taxation year of the trust in which the capital gains were realized or the dividends were received and distributed by it.

Part 3 – CDA components – Eligible capital property (ECP)

Record in these tables the most common amounts included in the eligible capital property (ECP) component of the CDA. This information is not meant to replace the calculation at line 400 in Part 7.

Section A: CDA components – List of ECP acquisitions and dispositions
 (for tax years ending before **February 28, 2000**)

1	2	3	4
Tax year-end (YYYY/MM/DD)	Cost of eligible capital property acquired	Proceeds of sale (minus outlays and expenses not otherwise deductible) from the disposition of all eligible capital property	Non-taxable portion of ECP sales
200	210	220	
1			
Total			

If you need more space, attach additional schedules.

Section B: CDA components – List of ECP dispositions
 (for tax years ending after **February 27, 2000** and before **January 1, 2018**)

1	2	3	4	5
Tax year-end (YYYY/MM/DD)	Cost of eligible capital property acquired	Proceeds of sale (minus outlays and expenses not otherwise deductible) from the disposition of all eligible capital property	Appropriate portion of the amount deducted as a bad debt per subsection 20(4.2) or as an allowable capital loss per subsection 20(4.3).	Non-taxable portion of ECP sales
250	261	262	270	
1	2006-12-31			
2	2007-12-31			
3	2008-12-31			
4	2009-12-31			
5	2010-12-31			
6	2011-12-31			
7	2012-12-31			
8	2013-12-31			
9	2014-12-31			
Total				

If you need more space, attach additional schedules.



Part 4 – Additional information – Capital dividends received from a corporation

For each capital dividend received, as recorded in column 4 in Part 2A and column 3 in Part 2B, give the name and business number of the corporation that paid the capital dividend and the date the dividend became payable.

	1	2	3
	Corporation's name	Business number	Date the dividend became payable (YYYY/MM/DD)
1	300	310	320

If you need more space, attach additional schedules.

Part 5 – Additional information – Capital dividends received from a Trust

For each capital dividend received, as recorded in column 7 in Part 2A and column 6 in Part 2B, give the name and trust number of the trust that paid the capital dividend and the date the dividend became payable.

	1	2	3
	Trust's name	Trust account number	Date the dividend became payable (YYYY/MM/DD)
1	330	335	340

If you need more space, attach additional schedules.

Part 6 – Additional information – Life insurance

Provide the following information if the CDA balance is to include **net** life insurance proceeds.

Please attach a letter from the insurance company stating whether the life insurance policy was a taxable or non-taxable policy.

Policy 1:

350 Name of insured individual	351 Name of beneficiary
352 Policy number	353 Adjusted cost base (ACB)
354 Total net proceeds received	355 Policy redemption date Year Month Day

Policy 2:

360 Name of insured individual	361 Name of beneficiary
362 Policy number	363 Adjusted cost base (ACB)
364 Total net proceeds received	365 Policy redemption date Year Month Day

Part 7 – CDA balance

Include the non-taxable portion of capital gains (including the non-taxable portion of capital gains from a trust after September 15, 2016) and the non-deductible portion of capital losses (total of column 3 in Part 2A **plus** total of column 2 in Part 2B. If negative enter "0")

.....	<u>2,419,977.00</u>	7A
Capital dividends received (total of column 4 in Part 2A plus total of column 3 in part 2B)		7B
Eligible capital property for tax years ending before January 1, 2018 (as calculated per former paragraphs 89(1)(c), (c.1) and (c.2). If negative, enter "0")	400	
Life insurance proceeds (total of column 5 in Part 2A plus total of column 4 in Part 2B. If negative, enter "0")		7C
Life insurance CDA ¹³	410	
Non-taxable portion of capital gains from a trust before September 16, 2016 (total of column 6 in Part 2A plus total of column 5 in Part 2B)		7D
Capital dividends from a trust (total of column 7 in Part 2A plus total of column 6 in Part 2B)		7E
Amounts from predecessor and subsidiary corporations ¹⁴ (For amalgamations and wind-ups before July 14, 1990 only)	420	
Subtotal (add amounts 7A to 7E and lines 400 to 420)	<u>2,419,977.00</u>	7F
Capital dividends that previously became payable (total of column 8 in Part 2A plus total of column 7 in Part 2B)		7G
CDA balance (amount 7F minus amount 7G. If negative, write "0")	430 <u>2,419,977.00</u>	

13 Include the balance of the corporation's life insurance CDA immediately before May 24, 1985, in accordance with paragraph 89(1)(e). For more information, see paragraphs 1.61 and 1.62 of Income Tax Folio S3-F2-C1, Capital Dividends.

14 For amalgamations and wind-ups before **July 14, 1990**, calculate the CDA balance of each predecessor or wound-up subsidiary corporation separately. Add these CDA balances to the CDA of the successor or parent corporation. Do not carry forward negative amounts, since these are considered to be nil.

For amalgamations and wind-ups after **July 13, 1990**, please refer to part 2A above.

- For amalgamations, see paragraph 87(2)(z.1).
- For wind-ups, see paragraph 88(1)(e.2).

Privacy notice

Personal information (including the SIN) is collected to administer or enforce the federal Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at canada.ca/cra-info-source.

Ontario Corporation Tax Calculation

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
------------------------------------------------------------------------	-------------------------------	-----------------------------------------------------

- Use this schedule if your corporation had a **permanent establishment** (as defined in section 400 of the federal Income Tax Regulations) in Ontario at any time in the tax year and had Ontario taxable income in the tax year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

Part 1 – Ontario basic income tax

Ontario taxable income (Note 1)	2,108,802	1A
Ontario basic rate of tax for the year	11.5 %	1B
Ontario basic income tax (amount 1A multiplied by amount 1B) (Note 2)	242,512	1C

Note 1: If your corporation had a permanent establishment only in Ontario, enter the amount from line 360, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Note 2: If your corporation had a permanent establishment in more than one jurisdiction or is claiming an Ontario tax credit in addition to Ontario basic income tax, Ontario corporate minimum tax, or Ontario special additional tax on life insurance corporations payable, enter amount 1C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if your corporation claimed the federal small business deduction under subsection 125(1).

Line 400 of the T2 return	2,137,534	2A	
Line 405 of the T2 return	2,108,802	2B	
Line 410 of the T2 return	500,000	2C	
Line 415 of the T2 return	3,304,692	2D	
Business limit reduction for tax years starting before April 7, 2022			
Amount 2C	x	Amount 2D	=
		11,250	2E
Business limit reduction for tax years starting after April 6, 2022			
Amount 2C	x	Amount 2D	=
500,000		3,304,692	18,359,400
		90,000	2F
		Amount 2E or amount 2F, whichever applies	18,359,400
		2G	2G
Line 515 of the T2 return			2H
Subtotal (amount 2C minus amount 2G minus amount 2H)			2I
Amount 2A, 2B or 2I whichever is the least			2J
Ontario domestic factor (ODF):	Taxable income for Ontario (Note 3)	2,108,802.00	=
	Taxable income for all provinces (Note 4)	2,108,802	1.00000
			2K
Amount 2J multiplied by amount 2K			2L
Ontario taxable income (amount 1A)		2,108,802	2M
Ontario small business income (amount 2L or 2M, whichever is less)			2N
Ontario small business deduction for the year			
Amount 2N	x	8.3 %	=
			2O

Enter Ontario small business deduction for the year (amount 2O) on line 402 of Schedule 5.

Note 3: Enter amount 1A.

Note 4: Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Ontario Research and Development Tax Credit

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
------------------------------------------------------------------------	-------------------------------	----------------------------------------------

- Use this schedule to:
 - calculate an Ontario research and development tax credit (ORDTC);
 - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
 - carry back an ORDTC earned in the tax year to reduce Ontario corporate income tax payable in any of the three previous tax years;
 - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
 - add an ORDTC transferred after an amalgamation or windup; or
 - calculate a recapture of the ORDTC.
- The ORDTC is a non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year. The ORDTC rate is:
 - 4.5% for tax years that end before June 1, 2016;
 - 3.5% for tax years that start after May 31, 2016; and
 - prorated for a tax year that ends on or after June 1, 2016, and includes May 31, 2016.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Complete and attach this schedule to the *T2 Corporation Income Tax Return* for the tax year.
- To claim this credit, you must also send in completed copies of the Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*, and the Schedule 31, *Investment Tax Credit - Corporations*, within 18 months of the tax year end.

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	6,638,448	A
Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B
Net eligible expenditures for the tax year (amount A minus amount B) (if negative, enter "0")		6,638,448	C
Eligible expenditures transferred to the corporation by another corporation	110		D
Subtotal (amount C plus amount D)		6,638,448	E
Eligible expenditures the corporation transferred to another corporation			115 F
Ontario SR&ED expenditure pool (amount E minus amount F) (if negative, enter "0")		6,638,448	G

Part 2 – Eligible repayments

The repayment of the ORDTC is calculated using the ORDTC rate that you used to determine your tax credit at the time your eligible expenditures were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayments for tax years that end before June 1, 2016 **210** x 4.5 % = **215** H

Repayment for a tax year that ends on or after June 1, 2016 and includes May 31, 2016. Complete the proration calculation below.

Number of days in the tax year before June 1, 2016	240	152	x	4.5 %	=	1.8689 %	1
Number of days in the tax year	241	366					
Number of days in the tax year after May 31, 2016	242	214	x	3.5 %	=	2.0464 %	2
Number of days in the tax year	243	366					

Subtotal (percentage 1 plus percentage 2) 3.9153 % 3

Repayments for a tax year that ends on or after June 1, 2016 and includes May 31, 2016 **211** x percentage 3 3.9153 % = **216** I

Part 2 – Eligible repayments (continued)

Repayments for tax years that start after May 31, 2016	212	x	3.5 %	=	217	J
Repayments made in the tax year of government or non-government assistance or contract payments that reduced eligible expenditures for first term or second term shared-use equipment acquired before 2014	220	x	1 / 4	=	225	K
Eligible repayments (total of amounts H to K)					229	L

Part 3 – Calculation of the current part of the ORDTC

For tax years that end before June 1, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)		x	4.5 %	=	200	M
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205	N
Eligible repayments (amount L in Part 2)						O
Current part of the ORDTC for tax years that end before June 1, 2016 (total of amounts M to O)					230	P

For a tax year that ends on or after June 1, 2016, and includes May 31, 2016

Number of days in the tax year before June 1, 2016	x	4.5 %	=		%	4	
Number of days in the tax year							
Number of days in the tax year after May 31, 2016	x	3.5 %	=		%	5	
Number of days in the tax year							
Subtotal (percentage 4 plus percentage 5)					%	6	
Ontario SR&ED expenditure pool (amount G in Part 1)		x	percentage 6	%	= 201	Q
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					206	R
Eligible repayments (amount L in Part 2)						S
Part of the ORDTC for a tax year that ends on or after June 1, 2016, and includes May 31, 2016 (total of amounts Q to S)					231	T

For tax years that start after May 31, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)	6,638,448	x	3.5 %	=	202	232,346	U
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					207		V
Eligible repayments (amount L in Part 2)							W
The ORDTC for tax years that start after May 31, 2016 (total of amounts U to W)					232	232,346	X

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Part 4 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year 462,273 Y

ORDTC expired after 20 tax years **300** Z

ORDTC at the beginning of the tax year (amount Y minus amount Z) **305** 462,273 AA

ORDTC transferred to the corporation on amalgamation or windup **310** BB

Current part of ORDTC 232,346 CC
(amount P, T or X in Part 3 whichever applies)

Are you waiving all or part of the current part of the ORDTC? **315** Yes 1 No 2

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Waiver of the current part of the ORDTC **320** DD

Subtotal (amount CC minus amount DD) 232,346 ▶ 232,346 EE

ORDTC available for deduction (total of amounts AA, BB and EE) 694,619 ▶ 694,619 FF

ORDTC claimed ** 242,512 GG
(Enter amount GG on line 416 on page 5 of Schedule 5, *Tax Calculation Supplementary – Corporations*)

ORDTC carried back to previous tax years (from Part 5) HH

Subtotal (amount GG plus amount HH) 242,512 ▶ 242,512 II

ORDTC balance at the end of the tax year (amount FF minus amount II) **325** 452,107 JJ

** This amount cannot be more than the lesser of the following amounts:
 – ORDTC available for deduction (amount FF); or
 – Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 on page 5 of Schedule 5).

Part 5 – Request for carryback of tax credit

	Year	Month	Day		
1 st previous tax year	2023	12	31 Credit to be applied	901 _____
2 nd previous tax year	2022	12	31 Credit to be applied	902 _____
3 rd previous tax year	2021	12	31 Credit to be applied	903 _____
Total (total of amount 901 to 903)(enter at amount HH in Part 4)					_____

Part 7 – Calculation of a recapture of ORDTC (continued)

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line SS.

OO	PP	QQ
Rate percentage that the transferee used to determine its federal ITC for qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act	Proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition	Amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act)
720	730	740
1.		

RR	SS	TT
Amount determined by the formula (OO x PP) - QQ (using the columns above)	Federal ITC earned by the transferee for the qualified expenditure that was transferred	Amount from column RR or SS, whichever is less
	750	
1.		

Total of column TT (enter at amount XX in Part 8) _____ **UU**

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205, 206, or 207 in Part 3, whichever applies. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line VV.

Corporate partner's share of the excess of ORDTC (enter at amount ZZ in Part 8) **760** _____ **VV**

Part 8 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount NN from Part 7)	_____	WW
Recaptured federal ITC for Calculation 2 (amount UU from Part 7)	_____	XX
Amount WW plus amount XX	=====	x 23.56 % = _____ YY
Corporate partner's share of the excess of ORDTC for Calculation 3 (amount VV from Part 7)	_____	ZZ
Recapture of ORDTC (amount YY plus amount ZZ) (enter amount AAA on line 277 on page 5 of Schedule 5)	=====	AAA

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act (ITA)* with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation.**

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Total expenditures for SR&ED		<u>6,152,526</u>
Add		
• payment of prior years' unpaid expenses (other than salary or wages)	+	<u> </u>
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	<u>1,253,698</u>
• other additions	+	<u> </u>
Subtotal	=	<u>7,406,224</u>
Less		
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	-	<u> </u>
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	-	<u> </u>
• 20% of contract expenditures for SR&ED performed on your behalf	-	<u>764,626</u>
• prescribed expenditures not allowed by regulations	-	<u> </u>
• other deductions	-	<u>3,150</u>
• non-arm's length transactions		
- expenditures for non-arm's length SR&ED contracts	-	<u> </u>
- purchases (limited to costs) of goods and services from non-arm's length suppliers	-	<u> </u>
Total	=	<u>6,638,448</u> I

Enter amount I on line 100 of Schedule 508.

Attached Schedule with Total

other deductions

Title other deductions

Description	Operator (Note)	Amount
Less: Outside Ontario Contracts		3,937 50
Less: 20% Contracts & Third-Party Payments Adjustment outside Ontario	-	787 50
	+	
	Total	3,150 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Ontario Corporate Minimum Tax

Corporation's name Hydro Ottawa Limited/Hydro Ottawa Limitee	Business number [REDACTED]	Tax year-end Year Month Day 2024-12-31
------------------------------------------------------------------------	-------------------------------	----------------------------------------------

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
 - 1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
 - 2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
 - 3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
 - 4) a congregation or business agency to which section 143 of the federal Act applies;
 - 5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
 - 6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	2,132,811,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	1,868,925,443
Total assets (total of lines 112 to 116)		4,001,736,443
Total revenue of the corporation for the tax year **	142	1,235,610,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	129,862,029
Total revenue (total of lines 142 to 146)		1,365,472,029

The corporation is subject to CMT if:

- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than \$5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than \$10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than \$50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than \$100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

*** Rules for total assets**

- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were \$1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were \$1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *		210	37,154,000
Add (to the extent reflected in income/loss):			
Provision for current income taxes/cost of current income taxes	220	2,636,000	
Provision for deferred income taxes (debits)/cost of future income taxes	222	54,382	
Equity losses from corporations	224		
Financial statement loss from partnerships and joint ventures	226		
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230		
Other additions (see note below):			
Share of adjusted net income of partnerships and joint ventures **	228		
Total patronage dividends received, not already included in net income/loss	232		
281	282		
283	284		
Subtotal		2,690,382	2,690,382 A
Deduct (to the extent reflected in income/loss):			
Provision for recovery of current income taxes/benefit of current income taxes	320		
Provision for deferred income taxes (credits)/benefit of future income taxes	322		
Equity income from corporations	324		
Financial statement income from partnerships and joint ventures	326		
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330		
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332		
Gain on donation of listed security or ecological gift	340		
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342		
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344		
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346		
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348		
Other deductions (see note below):			
Share of adjusted net loss of partnerships and joint ventures **	328		
Tax payable on dividends under subsection 191.1(1) of the federal Act multiplied by 3	334		
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336		
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338		
381	382		
383	384		
385	386		
387	388		
389	390		
Subtotal			B
Adjusted net income/loss for CMT purposes (line 210 plus amount A minus amount B)		490	39,844,382

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

*** Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIF1 (Schedule 125) on line 210.
- ** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.
- *** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.
- **** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.
- ***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) **515** 39,844,382

Deduct:

CMT loss available (amount R from Part 7)

Minus: Adjustment for an acquisition of control * **518**

Adjusted CMT loss available **C**

Net income subject to CMT calculation (if negative, enter "0") **520** 39,844,382

Amount from line 520 39,844,382 x $\frac{\text{Number of days in the tax year before July 1, 2010}}{\text{Number of days in the tax year}}$ x 4 % = 1

366

Amount from line 520 39,844,382 x $\frac{\text{Number of days in the tax year after June 30, 2010}}{\text{Number of days in the tax year}}$ x 2.7 % = 1,075,798 2

366

Subtotal (amount 1 **plus** amount 2) 1,075,798 3

Gross CMT: amount on line 3 above x OAF ** **540** 1,075,798

Deduct:

Foreign tax credit for CMT purposes *** **550**

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") 1,075,798 D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)

Net CMT payable (if negative, enter "0") 1,075,798 E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

**** Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

$$\frac{\text{Ontario taxable income ****}}{\text{Taxable income *****}} = \underline{\hspace{2cm}}$$

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were \$1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *	4,113,674	G
Deduct:		
CMT credit expired *	600	
CMT credit carryforward at the beginning of the current tax year * (see note below)	4,113,674	620 4,113,674
Add:		
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)	650	
CMT credit available for the tax year (amount on line 620 plus amount on line 650)		4,113,674 H
Deduct:		
CMT credit deducted in the current tax year (amount P from Part 5)		I
	Subtotal (amount H minus amount I)	4,113,674 J
Add:		
Net CMT payable (amount E from Part 3)	1,075,798	
SAT payable (amount O from Part 6 of Schedule 512)		
	Subtotal	1,075,798 K
CMT credit carryforward at the end of the tax year (amount J plus amount K)	670	5,189,472 L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
 – do not enter an amount on line G or line 600;
 – for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.
 For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)		4,113,674	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			1
For a corporation that is not a life insurance corporation:			
CMT after foreign tax credit deduction (amount D from Part 3)	1,075,798	2	
For a life insurance corporation:			
Gross CMT (line 540 from Part 3)		3	
Gross SAT (line 460 from Part 6 of Schedule 512)		4	
The greater of amounts 3 and 4		5	
	Deduct: line 2 or line 5, whichever applies:	1,075,798	6
	Subtotal (if negative, enter "0")		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Deduct:			
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 minus line 450 from Schedule 5)		71,241	
	Subtotal (if negative, enter "0")		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)			P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes 2 No

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 plus line 750) R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)
Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S plus line 760) 770 T

- * For the first harmonized T2 return filed with a tax year that includes days in 2009:
 - do not enter an amount on line Q or line 700;
 - for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

**ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS
AND REVENUE FOR ASSOCIATED CORPORATIONS**

Name of corporation Hydro Ottawa Limited/Hydro Ottawa Limitee	Business Number [REDACTED]	Tax year-end Year Month Day 2024-12-31
------------------------------------------------------------------	-------------------------------	----------------------------------------------

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return*.

	Names of associated corporations	Business number (Canadian corporation only) (see Note 1)	Total assets* (see Note 2)		Total revenue** (see Note 2)	
			200	300	400	500
1	Hydro Ottawa Holding Inc./Societe De Portefeuille	[REDACTED]		262,427,000		43,495,000
2	Energy Ottawa Inc./Energie Ottawa Inc.	[REDACTED]		197,690,000		12,848,000
3	Telecom Ottawa Holding Inc. / Societe De Portefeuille	[REDACTED]		21,014,000		320,000
4	PowerTrail Inc.	[REDACTED]		9,204,000		3,908,000
5	Moose Creek Energy Inc.	[REDACTED]		201		0
6	Chaudiere Hydro Inc. Hydro Chaudiere Inc.	[REDACTED]		142		7
7	Chaudiere Water Power Inc/Energie Hydraulique De L	[REDACTED]		821,000		2,305,000
8	2425932 ONTARIO INC.	[REDACTED]		87,473,693		636,894
9	CHAUDIERE HYDRO NORTH INC.	[REDACTED]		112		5
10	EO GENERATION GP INC.	[REDACTED]		100		0
11	THE GANANOQUE WATER POWER COMPANY	[REDACTED]		55,000		0
12	EONY GENERATION HOLDING INC.	NR		0		0
13	EONY GENERATION LIMITED	NR		0		0
14	9927891 CANADA INC.	[REDACTED]		30,401,101		0
15	ENERGY OTTAWA CABLE TESTING SERVICES INC.	[REDACTED]		1,912,000		157,000
16	HULL ENERGY GP INC.	[REDACTED]		1		0
17	Smart City Lighting Inc.	[REDACTED]		1		0
18	Envari Holding Inc.	[REDACTED]		26,890,000		0
19	Envari Energy Solutions Inc.	[REDACTED]		50,978,000		55,540,000
20	CHAUDIERE SERVICES INC./SERVICES CHAUDIERE IM	[REDACTED]		0		0
21	CHAUDIERE FINANCIAL INC./FINANCIERE DE LA	[REDACTED]		100		0
22	2725163 Ontario Inc.	[REDACTED]		6,421,890		310,890
23	Hiboo Networks Inc.	[REDACTED]		10,661,000		148,000
24	Hydro Ottawa Capital Corporation	[REDACTED]		1,153,126,000		10,193,233
25	Hydro Ottawa Energy Services Inc.	[REDACTED]		3,302,000		0
26	Hydro Ottawa District Energy Inc.	[REDACTED]		3,302,000		0
27	Hydro Ottawa Civic Community Utility Inc.	[REDACTED]		3,246,000		0

	Names of associated corporations	Business number (Canadian corporation only) (see Note 1)	Total assets* (see Note 2)	Total revenue** (see Note 2)
	200	300	400	500
28	Envari Construction Holding Inc	[REDACTED]	102	0
	Total		450 1,868,925,443	550 129,862,029

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.

Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation Hydro Ottawa Limited/Hydro Ottawa Limitee	Business Number [REDACTED]	Tax year-end Year Month Day 2024-12-31
------------------------------------------------------------------	-------------------------------	----------------------------------------------

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is \$1,000 for each qualifying work placement ending before March 27, 2009, and \$3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
 - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
 - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
 - the terms of the WP require the student to engage in productive work;
 - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
 - the student is paid for the work performed in the WP;
 - the corporation is required to supervise and evaluate the job performance of the student in the WP;
 - the institution monitors the student's performance in the WP; and
 - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information Bettina Yau	120 Telephone number including area code (613) 738-5499
Is the claim filed for a CETC earned through a partnership?*	150 1 Yes <input type="checkbox"/> 2 No <input checked="" type="checkbox"/>
If you answered yes to the question at line 150, what is the name of the partnership?	160
Enter the percentage of the partnership's CETC allocated to the corporation	170 _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year?	200 1 Yes <input checked="" type="checkbox"/> 2 No <input type="checkbox"/>
2. Was the corporation exempt from tax under Part III of the <i>Taxation Act, 2007</i> (Ontario)?	210 1 Yes <input type="checkbox"/> 2 No <input checked="" type="checkbox"/>

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 72,570,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is \$400,000 or less, enter 15% on line 310.
- If line 300 is \$600,000 or more, enter 10% on line 310.
- If line 300 is more than \$400,000 and less than \$600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300} - \text{minus } \$ 400,000}{\$ 200,000} \right) \right]$$

Eligible percentage for determining the eligible amount **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is \$400,000 or less, enter 30% on line 312.
- If line 300 is \$600,000 or more, enter 25% on line 312.
- If line 300 is more than \$400,000 and less than \$600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} - \text{minus } \$ 400,000}{\$ 200,000} \right) \right]$$

Eligible percentage for determining the eligible amount **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	Algonquin College	Electrical Engineering Technician
2.	Algonquin College	Mechanical Engineering Technology
3.	Algonquin College	Powerline Technician
4.	Algonquin College	Electrical Engineering Technician
5.	Algonquin College	Powerline Technician
6.	Algonquin College	Powerline Technician
7.	Algonquin College	Powerline Technician
8.	Algonquin College	Powerline Technician
9.	Algonquin College	Computer Programming
10.	Algonquin College	Powerline Technician
11.	Algonquin College	Powerline Technician
12.	Algonquin College	Powerline Technician
13.	Algonquin College	Electrical Engineering Technician
14.	Algonquin College	Business Intelligence System Infrastructure
15.	Algonquin College	Computer Programming
16.	Carleton University	Computer Science
17.	Carleton University	Computer Science
18.	Carleton University	Electrical Engineering Technician
19.	Carleton University	Computer Science
20.	Carleton University	Computer Science
21.	Ottawa University	Biomedical Mechanical Engineering
22.	Ottawa University	Biomedical Mechanical Engineering
23.	Sheridan College	Human Resources



	A Name of university, college, or other eligible educational institution	B Name of qualifying co-operative education program
24.	400 Algonquin College	405 Powerline Technician
25.		

	C Name of student	D Start date of WP (see note 1 below)	E End date of WP (see note 2 below)
1.	410 [REDACTED]	430 [REDACTED]	435 [REDACTED]
25.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below)		F2 Eligible expenditures after March 26, 2009 (see note 1 below)		X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
	450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)		
1.		10.000 %		25.000 %		15
2.		10.000 %		25.000 %		15
3.		10.000 %		25.000 %		17
4.		10.000 %		25.000 %		15
5.		10.000 %		25.000 %		14
6.		10.000 %		25.000 %		17
7.		10.000 %		25.000 %		17
8.		10.000 %		25.000 %		17
9.		10.000 %		25.000 %		16
10.		10.000 %		25.000 %		17
11.		10.000 %		25.000 %		17
12.		10.000 %		25.000 %		17
13.		10.000 %		25.000 %		15
14.		10.000 %		25.000 %		17
15.		10.000 %		25.000 %		14
16.		10.000 %		25.000 %		17
17.		10.000 %		25.000 %		17
18.		10.000 %		25.000 %		17
19.		10.000 %		25.000 %		17
20.		10.000 %		25.000 %		16
21.		10.000 %		25.000 %		15
22.		10.000 %		25.000 %		15
23.		10.000 %		25.000 %		16
24.		10.000 %		25.000 %		17
25.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures multiplied by eligible percentage) (see note 2 below)	H Maximum CETC per WP (see note 3 below)	I CETC on eligible expenditures (column G or H, whichever is less)	J CETC on repayment of government assistance (see note 4 below)	K CETC for each WP (column I or column J)
	460	462	470	480	490
1.	2,839	3,000	2,839		2,839
2.	2,839	3,000	2,839		2,839
3.	3,463	3,000	3,000		3,000
4.	2,839	3,000	2,839		2,839
5.	3,113	3,000	3,000		3,000
6.	3,473	3,000	3,000		3,000
7.	3,590	3,000	3,000		3,000
8.	3,546	3,000	3,000		3,000
9.	3,427	3,000	3,000		3,000
10.	3,520	3,000	3,000		3,000
11.	3,443	3,000	3,000		3,000
12.	3,514	3,000	3,000		3,000
13.	2,839	3,000	2,839		2,839
14.	3,908	3,000	3,000		3,000
15.	3,264	3,000	3,000		3,000
16.	3,734	3,000	3,000		3,000
17.	2,885	3,000	2,885		2,885
18.	3,218	3,000	3,000		3,000
19.	3,379	3,000	3,000		3,000



	G Eligible amount (eligible expenditures multiplied by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
20.	3,379	3,000	3,000		3,000
21.	3,354	3,000	3,000		3,000
22.	7,206	3,000	3,000		3,000
23.	3,522	3,000	3,000		3,000
24.	3,843	3,000	3,000		3,000
25.					

Ontario co-operative education tax credit (total of amounts in column K) **500** **71,241 L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L _____ x percentage on line 170 in Part 1 _____ % = **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

$$\text{Column G} = (\text{column F1} \times \text{percentage on line 310}) + (\text{column F2} \times \text{percentage on line 312})$$

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is \$1,000.

If the WP begins after March 26, 2009, the maximum credit amount for the WP is \$3,000.

If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

$$(\$1,000 \times X/Y) + [\$3,000 \times (Y - X)/Y]$$

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-185**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(B)_Hydro Ottawa 2026-2030 PIL Tax Model_20250604

8 Ref. 2: Accounting Procedures Handbook for Electricity Distributors, Article 220, January 1, 2012

9
10 **Preamble:**

11 In Tab H1 of Reference 1, Hydro Ottawa stated that the estimated base year property tax value is
12 \$3.7M in 2026. The estimated amount is based on current property tax payments with projected
13 increases. Hydro Ottawa further stated that the property tax values are recorded in three USoA
14 accounts:

- 15 • Account 6105, Taxes Other Than Income Taxes
16 • Account 5012, Station Buildings and Fixtures Expense
17 • Account 5015, Transformer Station Equipment - Operation Supplies and Expenses

18
19 **QUESTION(S):**

- 20
21 a) Please provide a breakdown of the base year property tax value of \$3.7M by USoA accounts.
22 b) Please provide a table outlining the property tax amounts reported in Account 6105 for the years
23 2023 – 2025, as well as the estimated property tax amounts for the years 2026 – 2030.
24 i) Please explain how the property tax amounts are derived for the test years.
25 ii) If applicable, please explain any variances between the property tax amounts provided
26 in part b) and those provided in the Revenue Requirement Workform for the test years.
27 iii) As defined in Reference 2, Taxes other than income taxes or PILs should only be
28 included in Account 6105. Please restate the property taxes that are booked in other
29 USoA accounts to 6105, if any.

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RESPONSE(S):

Hydro Ottawa assumes Reference 1 should refer to Section 3.1.6 of Schedule 1-3-1 - Rate Setting Framework based on the preamble.

a) A breakdown of the base test year property tax value by USofA account is provided in Table A below:

Table A – Property Taxes by USofA Account 2026 (\$'000s)

USofA Account	Test Year
	2026
5012 - Station Bldgs & Fixtures Exp	\$ 2,124
5015 - Transf Stat Equip-Ops Sup&Exp	\$ 282
6105 - Taxes Other Than Income Taxes	\$ 1,257
TOTAL	\$ 3,663

b) Table B shows the non-station related property tax amounts that are reported in Account 6105 for the years 2023 – 2025, as well as the estimated property tax amounts for the years 2026 – 2030. The breakdown for Accounts 5012 and 5015 is also included for completeness.

Table B – Property Taxes by USofA Account 2023-2030 (\$'000s)

USofA Account	Historical	Bridge		Test Years				
	2023	2024	2025	2026	2027	2028	2029	2030
5012 - Station Bldgs & Fixtures Exp	\$ 1,953	\$ 2,002	\$ 2,052	\$ 2,124	\$ 2,234	\$ 2,350	\$ 2,471	\$ 2,599
5015 - Transf Stat Equip-Ops Sup&Exp	\$ 260	\$ 266	\$ 273	\$ 282	\$ 297	\$ 312	\$ 328	\$ 345
6105 - Taxes Other Than Income Taxes	\$ 1,156	\$ 1,185	\$ 1,215	\$ 1,257	\$ 1,322	\$ 1,391	\$ 1,463	\$ 1,539
TOTAL	\$ 3,369	\$ 3,453	\$ 3,539	\$ 3,663	\$ 3,853	\$ 4,053	\$ 4,263	\$ 4,483

- 1 i) The forecast for property taxes in the 2026 Test Year is based on the increase observed
2 in 2024. The forecast for the 2027-2030 Test Years is escalated by the Custom Revenue
3 OM&A Factor (CROF) as proposed in Section 3.1.6 of Schedule 1-3-1 - Rate Setting
4 Framework.
- 5 ii) The property tax amounts for Account 6105 provided in part b) Table B for the
6 2026-2030 Test Years match those provided in Attachments 6-1-1(A) through (E)
7 Revenue Requirement Workforms for each of the years 2026 to 2030. Property tax
8 included in USofA accounts 5012 and 5015 are not shown on the property tax line in the
9 Revenue Requirement Workforms, these are included in OM&A.
- 10
- 11 iii) Article 220 of the Accounting Procedures Handbook (Reference 2) page 155 specifically
12 states that property taxes related to station buildings should be included in Account 5012
13 and Hydro Ottawa has historically recorded those property taxes related to station
14 buildings in Account 5012. For this Rate Application, the expenses, including the
15 property taxes formerly included in Account 5012 relating to Transmission Stations
16 operating >50kV have been reclassified to Account 5015. This was done to align the
17 operating expenses with the reclassification of the assets from Account 1808 to Account
18 1815. Account 6105 includes non-station related property taxes for Hydro Ottawa's
19 administration buildings.
- 20
- 21 Based on this interpretation of the guidance and examples provided in Reference 2,
22 Hydro Ottawa has not restated the property taxes that are booked in other USofA
23 accounts to Account 6105, although the combined total can be seen in Table B above.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-186**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(A)_OEB Appendix 2-H - Other Revenue_20250415

8 Ref. 2: Exhibit 6 / Tab 3 / Schedule 5 / p.7 (pdf p. 221)

9
10 **QUESTION(S):**

11
12 a) Account 4362 – Loss Retire of Utility and Other Property has a sub-category of “Net Book Value
13 and Proceeds”. What is included in this sub-category?

14 b) Please confirm that Account 4405 does not contain interest amounts related to DVAs. If not
15 confirmed, please revise Appendix 2-H to remove any interest amounts associated with DVAs.

16 c) Reference 2 states that material cash balances are not anticipated for Interest and Dividend
17 Income between 2024 and 2030. Please explain why there are no projected cash balances
18 between 2024 and 2030, while cash balances were present from 2021 to 2023.

19 d) Please confirm that Hydro Ottawa records MicroFit-related revenues under Account 4235. If not,
20 please update Appendix 2-H.

21
22 _____
23 **RESPONSE(S):**

24
25 a) Account 4362 is for costs associated with the disposal of fixed assets. This includes assets that
26 are retired early or are damaged, such as by a storm. When these assets are sold, Hydro
27 Ottawa might receive proceeds from the sale of the scrap materials, and the assets may also
28 still have a net book value at the time they are disposed of.

29
30 b) Confirmed, Account 4405 does not contain interest amounts related to DVAs.

- 1 c) As clarification, cash balances are anticipated for 2024 - 2030, however, they are not expected
2 to be material, which is the driver of the amounts captured in USoA account 4405. The historical
3 data referenced in 2021-2023 supports this statement given the immaterial annual amounts
4 noted.
- 5
- 6 d) Confirmed, Hydro Ottawa records miscellaneous service revenue to MicroFit customers under
7 Account 4235.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-187**

4
5 **EVIDENCE REFERENCE:**

6
7 Shared Services and Corporate Cost Allocation and Other Revenue

8 Ref. 1: Exhibit 6 / Tab 3 / Schedule 5 / p. 5 (pdf p. 219)

9 Ref. 2: Exhibit 4 / HOL_Attachment 4-2-1(A) – OEB – Shared Services and Corporate Cost
10 Allocation_20250415

11 Ref. 3: Exhibit 6 / HOL Attachment 6-3-1(A) – OEB Appendix 2-H – Other Revenue_20250415

12 Ref. 4: Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026
13 Rate Applications – Chapter 2, May 7, 2025 / pp. 43-44 (pdf pp. 49-50)

14
15 **Preamble:**

16 In reference 1, Hydro Ottawa states that revenues and costs incurred from the shared services
17 provided and received are recorded in other revenue under USoA Accounts 4325 Revenues from
18 Merchandise and 4330 Costs and Expenses of Merchandising, which is consistent with section
19 2.4.3.2 of reference 4.

20
21 OEB staff notes that the account information stated above is not accurate. According to the Filing
22 Requirements in reference 4:

- 23 • Revenue from affiliate transactions should be recorded in Account 4375, Revenues from Non
24 Rate-Regulated Utility and Operations.
- 25 • Expenses from affiliate transactions should be recorded in Account 4380, Expenses of Non
26 Rate-Regulated Utility Operations.

27
28 In addition, the Filing Requirements state that the balances recorded in Account 4375, Revenues
29 from Non Rate-Regulated Utility Operations, and Account 4380, Expenses of Non Rate-Regulated
30 Utility Operations (reference 3), must reconcile to the balances recorded in Appendix 2-N – Shared
31 Services and Corporate Cost Allocation (reference 2) for the three historical years.

1 QUESTION(S):

2

3 a) Please update the revenue and expense from affiliate transaction balances in Appendix 2-H
 4 according to the requirements noted above.

5 b) Please reconcile the balances in Accounts 4375 and 4380 with the balances in the Appendix
 6 2-N.

7

8 **RESPONSE(S):**

9

10 a) Hydro Ottawa has updated the revenue and expense from affiliate transactions balances to
 11 Accounts 4375 and 4380 in Appendix 2-H. Please see Attachment 1-Staff-1(A) - Chapter 2
 12 Appendices.

13

14 b) Please see Tables A & B below the balances in Account 4375 and 4380 reconcile to the
 15 balances in Appendix 2-N, excluding the Conservation First Framework (CFF).

16

17

Table A - USofA Account 4375 Reconcile to Appendix 2-N

	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
Appendix 2-H USofA 4375	\$ 3,774,697	\$ 4,346,206	\$ 4,884,058	\$ 4,897,621	\$ 4,929,458	\$ 4,780,148
Appendix 2-N Price for the Service excl CFF	\$ 3,774,697	\$ 4,346,206	\$ 4,884,058	\$ 4,897,621	\$ 4,929,458	\$ 4,780,148
Variance	-	-	-	-	-	-

18

19

Table B - USofA Account 4380 Reconcile to Appendix 2-N

	Historical Years			Bridge Years		Test Year
	2021	2022	2023	2024	2025	2026
Appendix 2-H USofA 4380	\$ 3,012,478	\$ 3,544,128	\$ 4,136,955	\$ 4,057,218	\$ 4,174,470	\$ 4,052,971
Appendix 2-N Cost for the Service excl CFF	\$ 3,735,930	\$ 4,324,586	\$ 4,859,443	\$ 4,865,327	\$ 4,907,938	\$ 4,758,628
Weighted Average Cost of Capital	\$ (723,452)	\$ (780,458)	\$ (722,488)	\$ (808,109)	\$ (733,468)	\$ (705,657)

20

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-188**

4
5 **EVIDENCE REFERENCE:**

6
7 Other Revenue

8 Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(A)_OEB Appendix 2-H - Other Revenue_20250415

9
10 **QUESTION(S):**

11
12 a) Please explain the large variances above the materiality threshold of \$1M for the following
13 accounts:

14 i) \$1.2M decrease in Account 4235 in 2026

15 ii) \$1.0M decrease in Account 4330 in 2027

16
17
18 **RESPONSE(S):**

19
20 a) The variances above the \$1M materiality threshold are explained as follows:

21
22 i) Account 4235 - Miscellaneous Service Revenues is projected to be \$1.2M (55%) lower
23 in Test Year 2026 compared to the 2025 Bridge Year forecast. This is primarily attributed
24 to planned rate reductions; most notably the proposed decrease in the Account Set Up
25 Charge from \$29 in 2025 to \$10 in 2026, which results in a revenue decrease of \$1.1M.
26 Please refer to Section 5.7 of Schedule 8-4-1 - Specific Service Charges for further
27 details on the decrease in the Account Set Up Charge.

28
29 ii) Account 4330 – Costs and Expenses of Merchandising is projected to increase by \$1.0M
30 in 2027 compared to 2026, not decrease as stated in the question. The \$1M increase in
31 account 4330 for 2027 is primarily due to a rise in internal labor costs for services

- 1 provided to third parties. This aligns with the workforce growth detailed in Attachment
- 2 4-1-3(C) - Workforce Growth and demonstrates the company's ability to meet increasing
- 3 demand. The costs increase is proportional to the revenue increase in Account 4325.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-189**

4
5 **EVIDENCE REFERENCE:**

6
7 Other Revenue

8 Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(A)_OEB Appendix 2-H - Other Revenue_20250415

9 Ref. 2: Exhibit 1 / Tab 3 / Schedule 1 / p. 26 (pdf Exhibit 1 part 1, p. 240)

10 Ref. 3: Exhibit 8 / Tab 3 / Schedule 2 / p. 2 (pdf p. 120)

11
12 Preamble:

13 Hydro Ottawa states in reference 2 that it “proposes to set both rates and revenue related to Other
14 Revenue for 5 years. Where rates are proposed to be adjusted in years two to five, for simplicity, an
15 annual inflation rate of 2.1% is proposed to avoid annual adjustments to the rates throughout the
16 rate term.”

17
18 In reference 1, OEB staff notes that only Account 4225 Late Payment Charges shows an increase
19 of 2.1% per year from 2027-2030 while Other Revenue accounts show different rates of growth or
20 decline for this period.

21
22 In reference 3, Hydro Ottawa states that “To remain consistent with OEB province wide charges,
23 such as the pole attachment and retailer service charges, Hydro Ottawa proposes to inflate the
24 2026 rate by the OEB approved inflationary factor for the 2027-2030 period. As a placeholder for
25 the OEB approved inflationary factors, the 2027-2030 rates have been escalated by 2.10%
26 annually.”

27
28 **QUESTION(S):**

29
30 a) Please explain Hydro Ottawa’s assumptions used to forecast other revenue amounts for each
31 account in reference 1 for the 2026 Test Year and for the 2027 to 2030 period.

- 1 b) For other revenues in reference 1 that will be adjusted based on the annual rate of inflation for
 2 the 2027 to 2030 period, please confirm whether Hydro Ottawa will update these revenues
 3 using the OEB's approved inflation factor when the information is available.
- 4 c) Please confirm whether Hydro Ottawa will update the pole attachment revenue (recorded in
 5 Account 4210 Rent from Electric Property) based on the OEB's approved pole attachment
 6 charge for the 2026-2030 period when the information is available.

7
8

9 **RESPONSE(S):**

10

- 11 a) Please see Table A below for each USofA account listed in Appendix 2H with the description of
 12 the forecast assumptions. Hydro Ottawa's assumptions used to forecast other revenue amounts
 13 for each account in reference 1 for the 2026 Test Year and for the 2027 to 2030 period, are
 14 detailed across the following schedules: Schedule 6-3-2 - Specific Service Charge Revenue,
 15 Schedule 6-3-3 - Late Payment Charge Revenue, Schedule 6-3-4 - Other Operating Revenue,
 16 and Schedule 6-3-5 - Other Income & Deductions

17
18

Table A - USofA Account Forecast Assumptions

USofA	USof Account Description	Description of Forecast Assumptions
4082	Retail Services Revenues	As per Section 3 of Schedule 6-3-4 Other Operating Revenue. The assumption used to forecast Retail Services Revenue amounts is based on the number of applicable retailer customers multiplied by the OEB generic rates.
4084	Service Trans Requests Revenue	As per Section 3 of Schedule 6-3-4 Other Operating Revenue. The assumption used to forecast Retailer Specified Meter Read Fees amounts is based on the number of applicable retailer customers multiplied by the OEB generic rates.
4086	SSS Administration Revenue	As outlined in Section 2 and 3 of Schedule 8-3-2 Standard Supply Service Charge. The assumption used to forecast Standard Supply Admin Charge amounts is based on the number of applicable retailer customers multiplied by the prescribed OEB generic rates in 2021-2025, 2026 was determined through a cost-based approach and 2027-2030 were based on the proposed inflation factor, pending OEB

USofA	USof Account Description	Description of Forecast Assumptions
		approval.
4090	Electric Services Incidental to Energy Sales	As per Section 4 of Schedule 6-3-4 Other Operating Revenue. The assumption used to forecast Fixed Distribution Charge amounts is based on the number of applicable retailer customers multiplied by the OEB generic rates.
4210	Rent from Electric Property	The assumption used to forecast Wireline Pole Attachments revenue amounts is based on the number of pole attachments multiplied by the 2024 generic provincial rate. Wireless Pole Attachment revenue was inflated per rate increases from customer agreements; assumption for duct rental was based on access agreements with third party; assumption for property rental was based on the amount of leases.
4225	Late Payment Charges	As per Schedule 6-3-3 Late Payment Charge Revenue. Hydro Ottawa anticipates an increase in Late Payment Charge (LPC) revenue for 2026, reflecting historical trends observed between 2021 and 2023. For the period from 2027 to 2030, LPC revenues are expected to continue rising at a more moderate and consistent pace
4235	Miscellaneous Service Revenues	As outlined in Schedule 6-3-2 Specific Service Charge Revenue and Schedule 8-4-1 Specific Service Charges. The assumption used to forecast Miscellaneous Services Revenue is based on the rate factored by the estimated volume.
4325	Revenues from Merchandise (Services to Third Parties)	As per Section 2 of Schedule 6-3-5 Other Income & Deductions. Forecast assumption was based on current trends, anticipated volume and the nature of customer requests.
4330	Costs and Exp of Merchandising (Services to Third Parties Costs)	As per Section 2 of Schedule 6-3-5 Other Income & Deductions, forecast assumption was based on current trends, anticipated volume and the nature of customer requests, and the addition of a new Non-Wires Customer Solutions Program, along with a new non-billable activity: Residential Electrical Isolations/Re-energizations.
4362	Loss Retire of Util & Oth Prop	As per Section 3 of Schedule 6-3-5 Other Income & Deductions, the forecast for Gains and Losses on Disposal of Utility Property is based on anticipated planned and unplanned asset retirements, including those from storm damage and new initiatives like the 2026 Metering Upgrades Program, all informed by normalized historical expenditures.

USofA	USof Account Description	Description of Forecast Assumptions
4375	SLA Services to Hydro Ottawa Affiliates	As per Section 4 of Schedule 6-3-5 Other Income & Deductions and Section 2 of Schedule 4-2-1 Shared Services and Corporate Cost Allocation, forecast assumption was based on transfer prices determined according to the Affiliate Relationships Code for Electricity Distributors and Transmitters (ARC).
4380	SLA Costs from Hydro Ottawa Affiliates	As per Section 4 of Schedule 6-3-5 Other Income & Deductions and Section 2 of Schedule 4-2-1 Shared Services and Corporate Cost Allocation, forecast assumption was based on transfer prices determined according to the Affiliate Relationships Code for Electricity Distributors and Transmitters (ARC).
4405	Interest and Dividend Income	As per Section 5 of Schedule 6-3-5 Other Income & Deductions shows that the assumption used to forecast Interest and Dividend Income is based on historical trend of the account

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- b) As noted in Schedule 1-3-1 - Rate Setting Framework, the Proposed 2026-2030 Custom Rate Framework for Other revenue is to set both rates and revenue for 5 years. Where rates are proposed to be adjusted in years 2 to 5 based on inflation, the rate is set at 2.1% for all four years (no adjustment based on the OEB approved inflation factor).
- c) Hydro Ottawa confirms it will not be updating the Pole Attachment revenue based on OEB's inflationary factor for 2026-2030. The revenue amount included in Table 2 of Schedule 6-3-2 - Specific Service Charge Revenue and Appendix 2-H is proposed to be set for all years as described in Table A above, without any annual updates.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-190**

4
5 **EVIDENCE REFERENCE:**

6
7 Other Revenue – Account 4362

8 Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(A)_OEB Appendix 2-H - Other Revenue_20250415

9 Ref. 2: Exhibit 6 / Tab 3 / Schedule 5 / Table 3 / p. 4 (pdf p. 219)

10
11 **QUESTION(S):**

12
13 a) OEB staff notes that the OEB Approved amounts in Table 3 in reference 2 are equal to the
14 amounts shown in Appendix 2-H, under actual and bridge year revenue in Account 4362 (row
15 41). Please reconcile and update Table 3 and/or Appendix 2-H as well as the variance analysis
16 explanation as required.

17
18
19 **RESPONSE(S):**

20
21 a) Yes, Hydro Ottawa confirms that the OEB Approved amounts in Table 3 in Reference 2 are
22 equal to the amounts shown in Appendix 2-H, under actual and bridge year revenue in Account
23 4362 (row 41).

24
25 Table A below provides the gains and losses before considering Account 1508 Sub-account
26 Gains and Loss on disposal of Fixed Assets Variance Account. As per Accounting Order
27 EB-2015-0004, the difference between the actual and forecasted losses from the Loss from
28 Retirement of Utility and Other Property (USoA 4362) is recorded in the variance account 1508
29 and offset with an adjustment in Account 4362. For further details, please refer to Schedule -
30 9-1-3 Group 2 Accounts.

1 **Table A – Loss from Retirement of Utility & Other Property - USofA 4362 (\$'000s)**

Ref	Net Gain/(Loss)	Historical Years			Bridge Years	
		2021	2022	2023	2024	2025
2	Amount before considering Account 1508	\$ 202	\$(1,234)	\$ 897	\$ 368	\$ 273
	Transfer out of 4362 to 1508	\$ (590)	\$ 483	\$(1,220)	\$ (704)	\$ (718)
1	Amount after considering Account 1508	\$ (389)	\$ (751)	\$ (323)	\$ (336)	\$ (445)
	OEB Approved	\$ (389)	\$ (751)	\$ (323)	\$ (336)	\$ (445)

2
 3 Because of these adjustments, Account 4362 will show no net variance from the OEB Approved
 4 level. However, the variances before and after considering Account 1508 are explained in Section 3
 5 of Schedule 6-3-5 - Other Income & Deductions.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **6-Staff-1**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Innovation-related Proposals in Rate Applications, March 20, 2025

8 Ref. 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition
9 for 2026 Rate Applications, May 7, 2025

10 Ref. 3: Exhibit 1 / Tab 3 / Schedule 4 / pp. 1-38 (pdf Exhibit 1 part 1, pp. 518-555)

11
12 **Preamble:**

13 On March 20, 2025, the OEB issued a letter for Innovation-related Proposals in Rate Applications
14 (the Letter) which provides guidance to support electricity distributors on incorporating
15 innovation-related proposals in rate applications. The Letter states that distributors should explore
16 and leverage additional sources of funding which include but are not limited to seeking out any
17 applicable tax incentives for innovative projects when incorporating innovation-related proposals as
18 part of or outside of their rebasing applications.

19
20 Section 2.6.2 of Reference 2 states that:

21 Distributors are expected to exercise sound tax planning and are expected, for rate-setting
22 purposes, to maximize tax credits and take the maximum deductions allowed.

23
24 **QUESTION(S):**

25
26 a) Please confirm whether Hydro Ottawa is planning to take any tax incentives for funding the
27 innovation initiatives outlined in Reference 3, and whether such incentives have been included
28 in the PILs forecast.

29 i) If confirmed, please elaborate further.

30 ii) If not confirmed, please explain why Hydro Ottawa doesn't apply tax incentives to
31 support its funding during its rebasing term.

1

2 **RESPONSE(S):**

3

4 a) Confirmed, Hydro Ottawa is planning to take advantage of any tax incentives when and if they
5 become available.

6

7 i) Hydro Ottawa has forecasted the scientific research and experimental development SR&ED
8 investment tax credits for the 2026-2030 Test Years. This forecast can be found in Schedule
9 6-2-1, Section 8, Table 4. The SR&ED investment tax credits have been reflected in the PILs
10 and Revenue Requirement calculations.

11

12 Hydro Ottawa has filed and received SR&ED investment tax credits since 2017. The
13 research, analysis and investigation into which projects and initiatives are eligible for
14 SR&ED investment tax credits is completed on an annual basis as part of Hydro Ottawa's
15 corporate tax return filings. Please see Schedule 6-2-1, Attachment 6-2-1(A) - 2023 Tax
16 Return for Hydro Ottawa's 2023 corporate tax return and specifically Form T661 for details
17 about Hydro Ottawa's eligible SR&ED projects for 2023. Please also see Attachment 6-
18 Staff-184(A) - 2024 Tax Return for Hydro Ottawa's 2024 corporate tax return and specifically
19 Form T661 for details about Hydro Ottawa's eligible SR&ED projects for 2024.

20

21 ii) Not applicable.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **7-Staff-191**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 7 / Tab 1 / Schedule 1 / p. 5 (pdf p. 5)

8
9 **Preamble:**

10 Hydro Ottawa indicates that it is obliged to ensure that at least 5,000 kW of power is available to
11 each Large Use customer as and when needed.

12
13 **QUESTION(S):**

- 14
15 a) How much power is reserved for the large use customers beyond the amount Hydro Ottawa is
16 already compensated for through rates?
17 b) From the perspective of costs imposed on Hydro Ottawa, how does this obligation to maintain
18 capacity differ from a standby service?
19 c) If the fixed charge for Large Use customers was designed to recover the costs of maintaining
20 the first 5,000kW of capacity, please explain the rational of also designing the variable charge to
21 be recovered from the first kW delivered.
22

23
24 **RESPONSE(S):**

- 25
26 a) Additional power is not reserved for large use customers beyond the amount Hydro Ottawa is
27 already compensated for through rates. When any new customer, including a large-use
28 customer, requests a connection, they must provide a load estimate. This estimate is used in
29 the distribution system's design, and the necessary capacity is reserved to meet that specific
30 load. In this standard scenario, Hydro Ottawa is compensated for this capacity through the
31 customer's regular rates.

- 1 The only situation where additional power is reserved is if a customer, particularly one with a
2 distributed energy resource (DER) such as a generator, requests it through the Standby rate
3 mechanism. This allows the customer to reserve grid capacity for times when their own DER
4 isn't running.
5
- 6 b) As noted in question a) above, Hydro Ottawa does not maintain capacity for any customers
7 including large use customers unless the customer has a standby capacity request and/or a
8 temporary hold due to a pending load upgrade project.
9
- 10 c) Hydro Ottawa clarifies that the example wasn't a proposed solution, but a demonstration that
11 there are other costs that could be included in the calculation of fair ceiling costs. Changing the
12 method for calculating a fixed charge wouldn't alter the total amount collected from customers,
13 which is determined by the cost allocation model based on revenue requirements. Essentially, if
14 the calculated cost of the 5,000 kW minimum commitment were included in the fixed portion of
15 rates, the amount to be recovered through a volumetric charge would correspondingly
16 decrease, leading to a lower variable charge per kW. The fixed charge would, however, more
17 accurately reflect Hydro Ottawa's cost of maintaining the customer.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **7-Staff-192**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 7 / Tab 1 / Schedule 1 / pp. 6-7 (pdf pp. 6-7)

8
9 **Preamble:**

10 Hydro Ottawa indicates that services weighting factors have been produced for all rate classes that
11 have secondary customers.

12
13 **QUESTION(S):**

- 14
15 a) Are primary customers required to supply their own connection to Hydro Ottawa’s primary
16 system?
17 b) Are secondary customers provided with a connection to Hydro Ottawa’s secondary system at
18 Hydro Ottawa’s expense?
19 c) For rate classes that have both primary and secondary customers, is the cost per customer
20 calculated as the weighted average of all customers, or only of the secondary customers?
21 d) What proportion of customers in each rate class are secondary customers?

22
23
24 **RESPONSE(S):**

- 25
26 a) Primary and secondary customers pay for their own connection costs, however basic
27 connection credits are given to new residential non-bulk connections that may offset all of the
28 connection costs.
29
30 b) See response in a)

- 1 c) Hydro Ottawa confirms that the cost per customer is the cost per secondary customer only.
- 2
- 3 d) The services weighting factor was developed on the basis of 2023 actual data. The proportions
- 4 of secondary customers for each relevant customer class are presented in Table A below. The
- 5 proportions have been carried forward to the 2026 - 2030 cost allocation models. They are not
- 6 expected to change substantially over the five year period.
- 7

8 **Table A - Secondary Customers Proportion By Class**

Class	Proportion Secondary
Residential	86.6%
GS <50	65.9%
GS 50 to 1,499 kW	3.1%
Street Light	100.0%
Sentinel	100.0%
Unmetered Scattered Load	96.1%

9

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **7-Staff-193**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 7 / Tab 1 / Schedule 1 / pp. 15-18 (pdf pp. 15-18)

8 Ref. 2: Exhibit 8 / Tab 5 / Schedule 2 / p. 1 (pdf p. 272)

9
10 **Preamble:**

11 The status quo sentinel light revenue-to-cost ratio is below unity (100%), and Hydro Ottawa
12 proposes to reduce it further below unity to mitigate a bill impact. The street lighting ratio, which
13 starts at a status quo 151.40% is proposed to be decreased to 120% over 5 years.

14 The balance of USoA account 1568 is proposed to be disposed of in 2027.

15
16 **QUESTION(S):**

- 17
18 a) Please indicate the bill impact that would result in the sentinel light rate class from maintaining
19 the status quo ratio.
- 20 b) Has Hydro Ottawa considered other options to mitigate the sentinel light impact other than a
21 reduction in revenue-to-cost ratio away from unity.
- 22 c) Please explain rationale for why a reduction in street lighting rates would require mitigation.
- 23 d) What would be the impact to the large use rate class if street lighting was brought to 120% in
24 2026?
- 25 e) Please provide any examples where a distributor has been granted approval in a rate
26 proceeding to begin disposition of a variance account in a future rate period.

1

2 **RESPONSE(S):**

3

4 a) Please refer to the interrogatory response 1-Staff-1. As a result of the updates (revenue
5 requirement, cost allocation, RTSR and Group 1 rate riders) detailed, the Sentinel Light total bill
6 remains under 10% and no mitigation is now required or being proposed.

7

8 b) Hydro Ottawa did not consider another alternative to a reduction in the revenue-to-cost ratio
9 away from unity. The class remains within the OEB's prescribed threshold of 80% to 120% and
10 the original adjustment proposed was only required for the 2026 test year. It is an efficient and
11 straight forward rate mitigation alternative. Revenue-to-cost ratio rises in subsequent years of
12 the rate application period to 95.6% in 2030.

13

14 c) A principal objective of the rate setting process is the maintenance of stable and predictable bill
15 impacts for customers. Hydro Ottawa has proposed to move the Street Light class to the
16 OEB-approved revenue to cost ratio through the 2026-2030 period to achieve stable rates for
17 both the Street Light class and the rate classification (Large User) receiving the offsetting
18 revenue requirement amount. A large shift in costs will cause a larger change to the Street Light
19 class and Large User class, compared to just the change in revenue requirement, or gradually
20 adjusting the revenue-to-cost ratios.

21

22 A similar approach was taken for the Sentinel Light class through the 2021-2025 rate term to
23 bring them within the OEB approved revenue-to-cost ratios.

24

25 d) The bill impacts for both Street Light and Large User have been provided below if the Street
26 Light class was moved to the 120% revenue-to-cost ratio in 2026 in Table B and C.

1

Table B - 2026 Large User Bill Impact

Large User (7,500 kW)	2026 Proposed	2026 No Mitigation
Distribution	\$69,298.68	\$70,800.93
Change in Distribution	\$7,606.50	\$9,108.75
% Change in Distribution	12.33%	14.76%
% Total Bill Change	0.97%	1.22%
R/C %	93.63%	95.54%

2

3

4

Table C - 2026 Street Light Bill Impact

Street Light (50 kW)	2026 Proposed	2026 No Mitigation
Distribution	\$956.13	\$855.18
Change in Distribution	\$27.25	-\$73.71
% Change in Distribution	2.93%	-7.94%
% Total Bill Change	-2.45%	-5.48%
R/C %	137.04%	120.00%

5

6

7

e) As part of Toronto Hydro's Approved 2025-2029 Settlement Agreement¹ the following 1508 accounts were approved to begin disposition in a future rate period:

8

9

- External Driven Capital - Disposition to start in 2027²
- Change in Useful Life of Assets (2026-2028) - Disposition to start in 2026
- Getting Ontario Connected Act Variance Account - Disposition to start in 2029
- Operations Centre Consolidation Plan - Disposition to start in 2029

10

11

12

¹ Ontario Energy Board, *Partial Decision and Order Toronto Hydro Electric System Limited Application for electricity distribution rates beginning January 1, 2025* EB-2023-0195 (November 12, 2024) Schedule A Page 25

² Toronto Hydro-Electric System Limited, *2025-2029 Custom Incentive Rate-setting Distribution Rate Application, THESL_Settlement Proposal_Schedule 21.2_Group 2 Rate Riders.xlsx*, EB-2023-0195 (August 16, 2024).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

7-Staff-194

EVIDENCE REFERENCE:

Ref. 1: Exhibit 7 / Tab 1 / Schedule 1 / Attachment F / pp. 1-8 (pdf pp. 24-31)

Preamble:

The proposed primary / secondary split for poles counts all poles that contain primary conductors (regardless of whether secondary conductors are present), as primary poles. All customers require the use of primary assets, so these poles are required to provide service to all downstream customers, regardless of their connection at primary or secondary voltage.

QUESTION(S):

- a) Does the addition of secondary conductors necessitate the use of more costly poles
 - i) Are there circumstances where taller poles would be required for the additional space taken up by secondary conductors?
 - ii) Are there circumstances where stronger poles would be required due to the extra weight of the secondary assets?
- b) If available, please provide a count or estimate of the number of poles that contain
 - i) Only primary conductors
 - ii) Primary and secondary conductors, and
 - iii) Only secondary conductors.

RESPONSE(S):

- 1 a)
- 2 i) When installing secondary conductors on new poles, Hydro Ottawa's standards are
- 3 followed. Taller poles may be needed due to the required separation from other lines (like
- 4 communication cables or primary power lines), or because of field conditions such such as
- 5 railroad crossings or large ditches, rather than solely because secondary conductors are
- 6 being added. All vertical clearances within Hydro Ottawa's standards are in compliance with
- 7 CSA 22.3 No. 1. The number of primary and secondary poles is provided in b).
- 8
- 9 ii) Hydro Ottawa standards typically account for the additional weight and forces for secondary
- 10 assets through non-linear analysis calculations, which follow CSA 22.3 No.1 requirements.
- 11 There may be specific one off locations where additional strength may be required, however
- 12 this would be validated through those non-linear analysis calculations.
- 13
- 14 b)
- 15 i) ii) iii) The proportionate split of poles used in Hydro Ottawa's original submission is based on
- 16 a count of in-service poles, owned by Hydro Ottawa, and by type, in Hydro Ottawa's GIS
- 17 database as at June 7, 2024. The results separated by only primary conductors, primary and
- 18 secondary conductors, and only secondary conductors are detailed in Table A below. It
- 19 should be noted, as stated in section 2.2 of 7-1-1 - Cost Allocation, that support poles that
- 20 do not carry wires are excluded from the pole count in Table 5 and in Table A below.
- 21
- 22

Table A - Pole Count with Primary and Secondary Conductors

Pole Classification	Number of In-Service Poles	% Split
Primary Only	20,397	91.09%
Primary and Secondary	19,278	
Secondary Only	3,879	8.91%
TOTAL	43,554	100.00%

23

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **7-Staff-195**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 7 / Tab 1 / Schedule 1 / Attachment G / p. 14 (pdf p. 50)

8
9 **Preamble:**

10 The best fit 1NCP for Street Lights for 2026 is less than every year from 2018 to 2023. The best fit
11 12NCP for Street Lights for 2026 however, is greater than every year from 2018 to 2023.

12
13 **QUESTION(S):**

- 14
15 a) Please explain the cause of this apparent discrepancy.
16 b) Please explain how the best fit 1 NCP for 2026 for Street Lights is less 4 times the 4 NCP and
17 less than 12 times the 12 NCP for the same year. The 1 NCP should be the highest peak of the
18 entire year, the 4 NCP is supposed to be the sum of the monthly peaks from the four highest
19 peaking months, and 12 NCP is supposed to be sum of all 12 monthly peaks.

20
21
22 **RESPONSE(S):**

- 23
24 a) During the first three years of the analysis, demand from the Streetlights class dropped due to
25 the LED replacement project. This decline slowed through 2023 and demand is expected to rise
26 again through 2030 as more streetlights are added. This pattern is represented in Table A
27 below.

28
29 The rapid decline in historical demand impacted the 1 NCP forecast value more than the 12
30 NCP value. In an environment of declining demand the top 12 monthly values became closer in

1 value and this created an anomaly where the 1 NCP value decreased while the 12 NCP value
2 remained relatively flat.

3
4 Hydro Ottawa recognizes that an averaging methodology is likely better suited than a trend to
5 account for declining demand. Because of this, the updated cost allocation models submitted in
6 response to Interrogatory 1-Staff-1 use a five-year average for the Street Light NCP values
7 instead of the original trended forecast. As streetlight demand is forecasted to increase through
8 2030, this anomaly is expected to disappear as trending becomes an appropriate forecasting
9 mechanism again.

10
11 **Table A - Streetlights Demand Trend 2018 - 2030**

Year	Consumption GwH
2018	31,723.37
2019	26,730.51
2020	22,495.94
2021	22,842.92
2022	22,059.32
2023	21,667.01
2024	21,765.27
2025	21,863.53
2026	21,961.79
2027	22,060.05
2028	22,158.32
2029	22,256.58
2030	22,354.84

12
13 b) Please see the response to a) above.

14
15 As the period of intense activity regarding LED replacement is removed from the Demand
16 Profile calculation, the 1 NCP anomaly reduces. It is expected that as demand begins to rise
17 slowly through the rate application period, the relationship between 1 NCP values and 12 NCP

1 will normalize. For this rate application, Hydro Ottawa will use an average value rather than a
 2 forecasted value to resolve the issue. Accordingly, Tab I8 Demand Data in the cost allocation
 3 models updated for 2024 as response to interrogatory 1-Staff-1 (Attachments 1-Staff-1(H) to
 4 Attachment 1-Staff-1(L)) has been updated to reflect average values for the Streetlight customer
 5 class. Table B below illustrates the impact on demand values of the decreasing demand from
 6 2018 to 2020. The comparison of 1 NCP to 4 NCP/4 and 12 NCP/12 illustrates the narrowing
 7 variation among the monthly peak values.

8
 9 **Table B - Streetlight Demand Profiles Comparison**

Demand Profile	Attachment 7-1-1 (G)				Updated cost allocation model			
	Trend	Compared to 1 NCP	Average	Compared to 1 NCP	Trend	Compared to 1 NCP	Average	Compared to 1 NCP
1 NCP	4,874	-	5,248	-	5,097	-	5,149	-
4 NCP	19,910	-	20,807	-	20,466	-	20,561	-
12 NCP	61,636	-	61,240	-	61,329	-	61,291	-
4 NCP average month	4,978	97.92%	5,202	100.89%	5,117	99.62%	5,140	100.17%
12 NCP average month	5,136	94.89%	5,103	102.83%	5,111	99.73%	5,108	100.81%

10

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **7-Staff-196**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 7 / Tab 1 / Schedule 3 / pp. 2-5 (pdf pp. 62-65)

8
9 **Preamble:**

10 Hydro Ottawa is providing three scenarios of backup generator operation, where the generator is on
11 for the entire billing period, off for the entire billing period, and is on for some of the billing period. It
12 then provides details for how much standby volume would be charged under each of these
13 scenarios. This is done for both the current implementation of standby rates, as well as the
14 proposed implementation of standby rates.

15
16 **QUESTION(S):**

- 17
18 a) For each of the three scenarios, please provide the bill that would result from the old structure at
19 status quo 2026 rates.
20 b) For each of the three scenarios, please provide the bill that would result from Hydro Ottawa's
21 proposed 2026 rates.

22
23
24 **RESPONSE(S):**

- 25
26 a) Based on the three scenarios detailed in Schedule 7-1-3 - Standby Service Charge. The bills
27 that would result from the current Standby structure, described in section 3.1, at 2025 status
28 quo rates have been detailed in table A.

1

Table A - Current Standby Structure at Status Quo Rates

	Status Quo - 2025 Approved	Status Quo - 2026 Proposed Rates
Example 1 - Generation ON Entire Period		
Billed Backup Demand (kW)	800	800
Monthly Service Charge	\$186.89	\$186.89
Volumetric Charge	\$1,995.20	\$3,211.52
TOTAL STANDBY CHARGE	\$2,182.09	\$3,398.41
Example 2 - Generation OFF Entire Period		
Billed Backup Demand (kW)	0	0
Monthly Service Charge	\$186.89	\$186.89
Volumetric Charge	0	\$0.00
TOTAL STANDBY CHARGE	\$186.89	\$186.89
Example 3 - Generation ON and OFF		
Billed Backup Demand (kW)	550	550
Monthly Service Charge	\$186.89	\$186.89
Volumetric Charge	\$1,371.70	\$2,207.92
TOTAL STANDBY CHARGE	\$1,558.59	\$2,394.81

2

3

- 4 b) Hydro Ottawa notes Schedule 7-1-3 - Standby Service Charge, Section 4.1 in the original filed
 5 evidence there was an error in Example 3. The billed backup demand should have been written
 6 as 350 kW. The error has been corrected in the bill impact calculations in Table B, which details
 7 the 2026 proposed structure and rates.

1

Table B - Proposed Standby Structure at 2026 Proposed Rates

	2026 Proposed
Example 1 - Generation ON Entire Period	
Billed Backup Demand (kW)	300
Monthly Service Charge	\$186.89
Volumetric Charge	\$1,204.32
TOTAL STANDBY CHARGE	\$1,391.21
Example 2 - Generation OFF Entire Period	
Billed Backup Demand (kW)	0
Monthly Service Charge	\$186.89
Volumetric Charge	0
TOTAL STANDBY CHARGE	\$186.89
Example 3 - Generation ON and OFF	
Billed Backup Demand (kW)	350
Monthly Service Charge	\$186.89
Volumetric Charge	\$1,405.04
TOTAL STANDBY CHARGE	\$1,591.93

2

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **8-Staff-197**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 8 / Tab 1 / Schedule 2 / pp. 5-7 (pdf pp. 6-8)

8
9 **Preamble:**

10 Hydro Ottawa has is proposing to increase the GS < 50 kW fixed charge above the ceiling as
11 calculated in the cost allocation model.

12
13 **QUESTION(S):**

14
15 a) As a scenario, please provide the fixed and variable charges that would result from limiting fixed
16 charges to the greater of the fixed charge from the prior year and the ceiling in the cost
17 allocation model, but not increasing the fixed proportion of total revenue in any year.

18
19 _____

20 **RESPONSE(S):**

21
22 The requested rates are detailed in Table A below and compared to calculated fixed and variable
23 rates as presented in the updated RRWFs submitted in Attachments 1-Staff-1(M)-(Q) - Revenue
24 Requirement Workforms.

25
26 Please see the response to 8.0-VECC-63 for a discussion of the impact of holding fixed rates at the
27 ceiling on the relationship between Residential and GS < 50 kW billed amounts. Specifically, holding
28 the fixed charge results in more small commercial customers paying less than the residential class
29 customers.

1 **Table A - General Service < 50kW Fixed and Variable Rate Comparison**

Year	Monthly Service Charge at Ceiling Rate		Monthly Service Charge at Proposed Rate	
	Monthly Service Charge	Volumetric Charge	Monthly Service Charge	Volumetric Charge
	per billing period	per kWh	per billing period	per kWh
2025 Actual	NA	NA	\$23.53	\$0.0305
2026 Test	\$26.89	\$0.0367	\$27.94	\$0.0362
2027 Test	\$28.60	\$0.0394	\$29.93	\$0.0388
2028 Test	\$30.79	\$0.0429	\$32.54	\$0.0422
2029 Test	\$32.93	\$0.0453	\$34.44	\$0.0447
2030 Test	\$35.33	\$0.0476	\$36.32	\$0.0471

2

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **8-Staff-198**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 8 / Tab 2 / Schedule 1 / Attachment A

8
9 **QUESTION(S):**

10
11 a) Hydro Ottawa has used the initial version of the RTSR model which does not produce a rate for
12 EV Charging customers. Please provide a new RTSR Model where the EV Rate Parameter is
13 used, and rates are produced for qualifying EV Charging customers.

14
15
16 **RESPONSE(S):**

17
18 a) Hydro Ottawa has provided the 2026 RTSR model which includes the RTSR EV Rate
19 Parameter as Attachment 1-Staff-1(D) - 2026_RTSR_Workform_EV.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD**

2
3 **8-Staff-199**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 8 / Tab 3 / Schedule 2 (pdf pp. 119-123)

8
9 **QUESTION(S):**

10
11 a) Hydro Ottawa is proposing an updated SSS administrative charge. Has Hydro Ottawa
12 performed any consultation on the updated SSS admin charge, and if so, what has been the
13 feedback?

14 _____

15 **RESPONSE(S):**

16
17 a) Hydro Ottawa did not perform a specific consultation on the updated SSS administrative charge.
18 The updated SSS charge revenue was incorporated into the base revenue requirement and the
19 utility specific SSS rate was included in the bill impacts in the 2026-2030 customer engagement.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **8-Staff-200**

4
5 **EVIDENCE REFERENCE:**

6
7 1: Exhibit 8 / Tab 4 / Schedule 1 / pp. 1-3 (pdf pp. 119-123)

8
9 **Preamble:**

10 Hydro Ottawa is proposing updated specific service charges, based on a 2024 review of costs. It
11 then proposes to increase these charges by an inflationary rate of 2.1% rounded to the nearest
12 dollar.

13
14 Some charges such as the Easement Certificate are not inflating over the five years. In that
15 instance, a 2.1% increase on \$30 would be 62 cents, which would normally round to one dollar.

16
17 **QUESTION(S):**

- 18
19 a) Does Hydro Ottawa propose to inflate using the 2.1% inflationary rate, or use the OEB approved
20 inflationary factor as it is known?
- 21 b) Please explain if, for the purpose of calculating the next year's rate, Hydro Ottawa is proposing
22 to track a precise charge for each year or to apply inflation each year to the prior year's rounded
23 rate? If neither, please explain.
- 24 c) If the inflation rate is subject to change, are the rates that are currently behaving as fixed also
25 subject to change?
- 26 d) Please provide details of any consultation performed on the proposed specific service charges.

1

2 **RESPONSE(S):**

3

4 a) Hydro Ottawa proposes to inflate Specific Service Charges using a 2.1% inflationary rate. Hydro
5 Ottawa is not proposing to update these charges annually, with the exception of Wireline Pole
6 Attachment charges, and is seeking approval for the 2026-2030 rates as detailed in Table 1 of
7 Schedule 8-4-1 - Specific Service Charges. Also see Table 1 of Schedule 1-3-1 - Rate Setting
8 Framework for further details.

9

10 b) For the purpose of calculating the next year's rate, Hydro Ottawa tracked a precise charge for
11 each year, applied a 2.1% inflation factor to prior year precise charge, then subsequently
12 rounded up to the nearest dollar. As detailed in Schedule 8-4-1 - Specific Service Charges some
13 of the charges, such as Easement Certificate and Account Set Up Charge, are proposed to be
14 maintained at the same rate for the 2026-2030 period.

15

16 c) See response to question a)

17

18 d) Hydro Ottawa undertook a review of many routine service charges to ensure they reflected the
19 associated costs of providing services and achieved efficiencies in the 2021-2024 period. This
20 review resulted in the discontinuation and reduction of some charges. However, Hydro Ottawa
21 did not perform any consultation on the proposed specific service charges.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

9-Staff-201

EVIDENCE REFERENCE:

Ref. 1: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

Ref. 2: EB-2019-0261, Draft Rate Order, December 11, 2020 / Chapter 2 Appendices

Ref. 3: Attachment 6-3-1(A)/ Appendix 2-H – Other Revenue, April 15, 2025

Ref. 4: Exhibit 9 / Tab 1 / Schedule 3 / pp. 3-5 (pdf pp. 13-15)

Ref. 5: Exhibit 6 / Tab 3 / Schedule 5 / p. 4 (pdf p. 218)

Ref. 6: Exhibit 9 / Tab 2 / Schedule 1 / pp. 6-7 (pdf pp. 82-83)

Ref. 7: EB-2015-0004, Decision and Rate Order, Schedule C, December 22, 2015

Preamble:

Sub-account 1508 Gains and Losses on Disposal of Fixed Assets was established in the accounting order approved in 2016-2020 Custom IR Decision and Order. The account was to record the difference between the forecast and actual loss on the disposal of fixed assets, related to the retirement of assets or damage to plant. Table 2 in Schedule 9-1-3 outlines the forecasted loss from the retirement of utility and other property for 2026 -2030. In Reference 4, Hydro Ottawa stated that costs related to significant weather damages are not included in the budgeted amounts in Account 4362, as such costs are unpredictable. Hydro Ottawa proposed to continue this 1508 Sub-account to record the difference between the forecast loss and the actual gain/loss on the disposal of fixed assets related to scheduled retirements or unforeseen damage to its plant, including costs associated with weather-related damage for Test years 2026-2030. In Reference 6, Hydro Ottawa proposed to reserve the right to use a Z-factor cost recovery mechanism in the future.

In Reference 5, Hydro Ottawa stated that the implementation of its metering upgrades program will commence in 2026, which will increase asset derecognition charges from \$0.4M to \$0.8M per year.

1 QUESTION(S):

2

3 a) According to Tab 2-H of Reference 2, the forecasted amount was an annual loss of \$388,726 for
 4 the period of 2021 to 2025 as recorded in Account 4362 – Loss from Retirement of Utility and
 5 Other Property.

6 i) Please clarify the OEB approved baseline amounts for 2022 and 2023 outlined in Table
 7 1 of Reference 4 in relation to Reference 2.

8 b) Please provide a breakdown of the annual variances recorded in this variance account related
 9 to the unforeseeable events/extreme weather.

10 c) Please explain how the estimated losses for 2026 to 2030 were determined.

11 d) Please confirm whether the estimated annual increase of \$0.4M in asset derecognition charges,
 12 as described in Reference 5, is included in the estimated losses for 2026 to 2030 in Account
 13 4362, particularly for the year 2026.

14 e) Please confirm that the costs recorded in Sub-account 1508 Gains and Losses on Disposal of
 15 Fixed Assets will be excluded from any potential Z factor claims.

16

17
 18 **RESPONSE(S):**

19

20 a) For the 2016-2020 Custom IR term, there was an annual forecast of \$198K. The forecast for
 21 2021-2025 Custom IR term fluctuates annually. Tab 2-H of Reference 2 stops at the year 2021
 22 and does not forecast the 2021 recorded amount for 2022 to 2025. See the below table for the
 23 yearly forecast amounts approved for 2021 to 2025.

24

25 **Table A - Yearly Forecast Amounts Approved for 2021-2025**

Net (Gain)/Loss	2021 Approved	2022 Approved	2023 Approved	2024 Approved	2025 Approved	Total
Estimate	\$ 389	\$ 751	\$ 323	\$ 336	\$ 445	\$ 2,243

26

- 1 i) See response for a).
2
- 3 b) The 2022 Derecho storm resulted in asset derecognition charges of \$1M, which is the major
4 driver of the increased loss on disposal experienced in 2022 compared to the other historical
5 years 2021 and 2023.
6
- 7 c) Hydro Ottawa confirms the estimated annual increase of \$0.4M in asset derecognition charges,
8 as described in Reference 5, is included in the estimated losses for 2026 to 2030 in Account
9 4362, particularly for the year 2026.
10
- 11 d) Hydro Ottawa confirms that the costs recorded in Sub-account 1508 Gains and Losses on
12 Disposal of Fixed Assets will be excluded from any potential Z factor claims.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-202**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 1 / p. 6 (pdf p. 6)

8 Ref. 2: Exhibit 9 / Tab 1 / Schedule 3 / p. 42 (pdf p. 52)

9 Ref. 3: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition
10 for 2026 Rate Applications, May 7, 2025, p.68

11
12 Preamble:

13 In Reference 1, Hydro Ottawa proposed to discontinue the generic Group 2 Account 1511,
14 Incremental Cloud Computing Implementation Costs.

15
16 In Reference 2, Hydro Ottawa stated that the forecasted cloud computing costs are included in the
17 proposed OM&A budget outlined in Schedule 4-1-2. Hydro Ottawa further proposed to establish a
18 new deferral account for incremental cloud computing costs.

19
20 OEB staff notes that the requested new DVA for incremental cloud computing costs is not provided
21 in Schedule 9-2-1 – New Deferral and Variance Accounts.

22
23 **QUESTION(S):**

24
25 a) Please confirm whether a new DVA for incremental cloud computing is requested.

26 i) If yes, please provide the details for the proposed new DVA, including comments on the
27 three eligibility criteria for the establishment of a new DVA as outlined in Section 2.9.2 of
28 Reference 3.

29 ii) If not, please update this exhibit accordingly.

1

2 **RESPONSE(S):**

3

4 a) A new DVA for incremental cloud computing is not being requested. The account was
5 contemplated during the drafting of the application. However, after deciding to defer the
6 implementation of the Enterprise Resource Planning (ERP) upgrade, it was determined that the
7 remaining relevant amounts would not justify the need or effort in establishing and maintaining
8 the account. The statement in Reference 2 was included in error and was intended to be
9 removed before the evidence was submitted.

10

11 Hydro Ottawa will continue to evaluate its planned cloud computing expenditures and may
12 determine the new DVA for incremental cloud computing in future applications.

13

14 i) Not applicable. See response to part a).

15

16 ii) As per Appendix A filed in the introductory letter of Hydro Ottawa's Interrogatory responses,
17 Hydro Ottawa notes that the sentence on page 42 (lines 16-17) of Schedule 9-1-3 - Group 2
18 Accounts, "Hydro Ottawa is proposing a new deferral account for incremental cloud
19 computing costs, as detailed in Schedule 9-2-1 - New Deferral and Variance Accounts" was
20 included in error and should be disregarded.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-203**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 3 / pp. 5-10 (pp. 15-20 of pdf)

8 Ref. 2: EB-2019-0261, Draft Rate Order, December 11, 2020 / Deferral and Variance Account
9 Continuity Schedule

10 Ref. 3: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

11
12 Preamble:

13 In Reference 2, the closing principal balance for Account 1508, Earnings Sharing Mechanism
14 (ESM) Variance Account as of Dec. 31, 2019, is a credit of \$4,985,981.

15
16 In Reference 3, the opening principal balance for the ESM variance account as of January 1, 2020,
17 is a credit of \$3,672,684.

18
19 In Reference 1, Hydro Ottawa stated that there is no over-earning in 2020, 2022, and 2023. As
20 outlined in Tables 3 and 4, the ratepayer's shares of overearning recorded for 2019 and 2021 are
21 \$1,152K and \$840K, respectively.

1

Sub-account ESM Variance Account	A. Transactions	B. Principal Adjustments	C. OEB Approved Disposition - Principal	D. Total Changes in Principal (A+B-C)	E. Interests (incl. Adjustments)	F. OEB Approved Disposition - Interests	G. Total Changes in Interests (E-F)	Total (D+G)
Opening Balance	(3,672,684)	-		(3,672,684)	(101,330)		(101,330)	(3,774,014)
2020	(1,313,297)	(354,767)		(1,668,065)	(68,338)		(68,338)	(1,736,402)
2021	(1,809,267)		(4,985,981)	3,176,714	(2,022)	(210,025)	208,002	3,384,717
2022	700,743	-		700,743	(41,654)		(41,654)	659,090
2023		311,597		311,597	(99,323)		(99,323)	212,274
Projected Interest on Dec. 31, 2023				-	(101,155)		(101,155)	(101,155)
Total Claim	(6,094,505)	(43,170)	(4,985,981)	(1,151,694)	(413,822)	(210,025)	(203,797)	(1,355,491)

2

1 OEB staff has summarized the amounts recorded in Account 1508, Sub-account ESM Variance
 2 Account, as reported in Reference 3, in the table below.

3

4 OEB staff has further calculated the variances between the ratepayer's share of overearning
 5 reported in Reference 3 and the amounts reported in Reference 1 in the table below.

6

7

Sub-account ESM Variance Account	A. Ref. 1 - Transactions	B. Ref. 1 -Principal Adjustments	C. Ref. 1 -Total Adjusted Principal Transactions (A+B)	D. Ref. 3 - Ratepayer's Share of Overearning	Variance (C-D)
2019	-	-	-	(1,152,000)	1,152,000
2020	(1,313,297)	(354,767)	(1,668,065)	-	(1,668,065)
2021	(1,809,267)		(1,809,267)	(840,000)	(969,267)
2022	700,743	-	700,743	-	700,743
2023		311,597	311,597	-	311,597
Total	(2,421,821)	(43,170)	(2,464,991)	(1,992,000)	(472,991)

8 QUESTION(S):

9

10 a) Please confirm and explain the differences between the opening balance for the ESM Variance
 11 Account for a credit of \$3,672,684 in Reference 3 and the closing balance for a credit of
 12 \$4,985,981 as reported in Reference 2.

13 b) Please explain the differences calculated by the OEB staff and clarify the transactions and
 14 principal adjustments recorded in the Sub-account 1508 ESM for the years 2019 – 2023 related
 15 to Tables 3 and 4 in Reference 1.

- 1 i) Please update the DVA Workform if necessary.
- 2 c) In Reference 1, Hydro Ottawa proposed the continuation of the ESM Variance Account with
3 modification, i.e., establishing a deadband tied to Hydro Ottawa Adjusted PEG model results.
4 Please explain the impacts of the requested modifications on Hydro Ottawa and Hydro Ottawa's
5 ratepayers.
- 6
- 7

8 **RESPONSE(S):**

9

10 a) Hydro Ottawa confirms the closing balance for ESM variance account is \$4,985,981.
11 Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account originally submitted was
12 using a previous version of the OEB Workform Deferral and Variance Account dated May 5,
13 2020 for the closing 2019 principal balances. The DVA Continuity Schedule in 1-Staff-1 has
14 been updated to match EB-2019-0261, Draft Rate Order, December 11, 2020 Deferral and
15 Variance Account Continuity Schedule. Please see Attachment 1-Staff-1(C) - OEB Workform -
16 2026 DVA Continuity Schedule.

17

18 b) Hydro Ottawa has recreated Table A as suggested by OEB staff. The below table shows no
19 variances when transactions are reported in the year to which they relate. However the yearly
20 balances listed in the Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account,
21 April 28, 2025 reflect the year they were recorded and those balances align with the RRR
22 Reporting. The only change in the updated Deferral and Variance Account Continuity Schedule
23 in 1-Staff-1 is to reflect 2024 actual amounts and adjustment noted in (a); balances from periods
24 prior to 2024 remain unchanged.

25

26 The overall variance of \$307 is due to Reference 3 (Table within Schedule 9-1-3 - Group 2
27 Accounts) being rounded to the thousands, but the DVA Continuity Schedule (Reference 1) is
28 not.

1 As per the 2021-2025 Approved Settlement Agreement, the ESM Variance Account has been
 2 modified such that starting in 2021 the ESM will function as a cumulative account. The balance
 3 (if any) will be cleared and credited on a final basis to customers at the end of the five-year rate
 4 term. Therefore, the ratepayer's shares of overearning recorded in 2021 for \$840K has not been
 5 recorded into the ESM Variance Account as the cumulative balance for years 2021-2023 is an
 6 underearning.

7
8

Table A - Variance Table for Reference 1 and Reference 3

Year	Ref. 1 - Transactions	Ref. 1 -Principal Adjustments	Ref. 1 -Total Adjusted Principal Transactions	Ref. 3 - Ratepayer's Share of Overearning	Variance
	A.	B.	C = (A+B)	D	(C-D)
2019	-	\$ (1,151,693)	\$ (1,151,693)	\$ (1,152,000)	\$ 307
2020	\$ (354,767)	\$ 354,767	-	-	-
2021	\$ (1,809,267)	\$ 1,809,267	-	-	-
2022	\$ 700,743	\$ (700,743)	-	-	-
2023	-	-	-	-	-
Total	\$ (1,463,291)	\$ 311,598	\$ (1,151,693)	\$ (1,152,000)	\$ 307

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19

i) See response to a), no update is necessary.

c) As a customer protection mechanism, Hydro Ottawa proposes an ESM which facilitates sharing 50:50 with customers any cumulative utility earnings above 150 basis points (dead-band) of the approved rate of ROE. The utility would only share earnings that exceed the threshold above the utility's return on equity (ROE), with no sharing if its earnings fall below its allowed ROE.

The proposed modifications to Hydro Ottawa's ESM are intended to enhance consumer protection and strengthen the link between incentive regulation and sustained cost performance.

1 **Impacts on Hydro Ottawa’s Ratepayers**

- 2 • By lowering the deadband from the Ontario Energy Board’s (OEB) standard 300 basis
3 points to 150 basis points above the approved return on equity (ROE), customers would
4 begin to share in excess earnings sooner than under the standard approach.
- 5 • This earlier sharing means that any earnings materially above the allowed ROE would
6 be passed back to customers more quickly.
- 7 • The incorporation of an efficiency performance test, tied to maintaining at least a Cohort
8 III efficiency position in the adjusted PEG Model by the end of the rate term, adds an
9 additional safeguard. If Hydro Ottawa fails to meet this efficiency standard, customers
10 would receive 100% of any earnings above the approved ROE, rather than only those
11 above the deadband.

12

13 **Impacts on Hydro Ottawa**

- 14 • The reduced deadband increases the likelihood that Hydro Ottawa will share excess
15 earnings with customers, limiting the utility’s ability to retain earnings above the allowed
16 ROE.
- 17 • The efficiency performance condition creates an additional performance requirement;
18 failure to maintain the Cohort III efficiency position would result in a more significant
19 earnings transfer to customers. This heightens the incentive for Hydro Ottawa to
20 continue improving productivity and cost efficiency throughout the rate term.
- 21 • While these modifications reduce potential earnings retention for Hydro Ottawa, they
22 align with the utility’s commitment to continuous improvement and to balancing
23 shareholder returns with customer value.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-204**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 3 / p. 11 (pdf p. 21)

8
9 **Preamble:**

10 Hydro Ottawa states it “received an invoice from Hydro One related to a 2019 CCRA as well as a
11 refund from Hydro One. Although the 2019 CCRA balance has been disposed of, Hydro Ottawa has
12 recorded a return of \$23k (principal balance) to rate payers in this account.”

13
14 **QUESTION(S):**

- 15
16 a) For both the mentioned invoice and the refund:
- 17 i) Please categorize the costs as construction costs or load true-up.
 - 18 ii) Please provide the agreements between Hydro Ottawa and Hydro One.
 - 19 iii) Please provide any invoices and calculations from Hydro One (i.e. output of the Hydro
20 One DCF model).
 - 21 iv) For the invoice, if the invoice was due to reduced or unrealized load, please explain why
22 the load forecast at the time of the agreement with Hydro One was not realized.

23
24

25 **RESPONSE(S):**

- 26
27 a) Please refer to the response to interrogatory 2-Staff-205, part a).

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-205**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 3 / pp. 11-17 (pdf pp. 21-27)

8 Ref. 2: OEB Letter re: Adjustments to Correct for Errors in Electricity Distributor “Pass-Through”
9 Variance Accounts After Disposition. October 31, 2019

10 Ref. 3: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

11 Ref. 4: EB-2019-0261, Draft Rate Order, December 11, 2020 / Deferral and Variance Account
12 Continuity Schedule

13 Ref. 5: EB-2019-0261, Settlement Proposal, December 11, 2020 / Attachment 6 Accounting Order,
14 pp. 1-2

15
16 **Preamble:**

17 In Reference 1, Hydro Ottawa states it “received an invoice from Hydro One related to a 2019
18 CCRA as well as a refund from Hydro One. Although the 2019 CCRA balance has been disposed
19 of, Hydro Ottawa has recorded a return of \$23k (principal balance) to rate payers in this account.”

20
21 Hydro Ottawa further states that it seeks to clear the (\$23K) adjustment to the 2019 value and the
22 principal balance of \$1,064K for the year 2020 as part of this Application.

23
24 Hydro Ottawa has provided the following sample journal entry as part of the draft accounting order
25 for the continuation of the Sub-account CCRA on page 16 of Reference 1.

Table 10 - CCRA Sample Journal Entry

Account	Debit	Credit
Account 1508 - Sub-Account CCRA	x,xxx.xx	
Account 4080 – Distribution Services Revenue		x,xxx.xx
To record revenue requirement difference as actual CCRA payments are higher than forecasted		
Account 1508 - Sub-Account CCRA	x,xxx.xx	
Account 6035 - Other Interest Expense		x,xxx.xx
To record carrying charges		

1
2
3
4
5

OEB staff has compiled the variances between the CCRA amounts reported in Reference 3 and the amounts reported in Table 8 of Reference 1 in the table below.

Sub-account CCRA	A. Ref. 3 - Transactions	B. Ref. 3 – Principal Adjustments	C. Ref. 3 – Total Adjusted Principal Transactions (A+B)	D. Ref. 1 – CCRA Revenue Requirement Calc.	Variance (C-D)
2021	(263,730)	-	(263,730)	(308,000)	44,270
2022	(1,508,337)	-	(1,508,337)	(1,026,000)	(482,337)
2023	119,723	(25,681)	94,041	(273,000)	367,041
Total	(1,652,344)	(25,681)	(1,678,026)	(1,607,000)	(71,026)

6
7
8
9
10

QUESTION(S):

a) For both the mentioned invoice and the refund:

i) Please categorize the costs as construction costs or load true-up.

- 1 ii) Please provide the agreements between Hydro Ottawa and Hydro One.
- 2 iii) Please provide any invoices and calculations from Hydro One (i.e., output of the Hydro
- 3 One DCF model).
- 4 iv) For the invoice, if the invoice was due to reduced or unrealized load, please explain why
- 5 the load forecast at the time of the agreement with Hydro One was not realized.
- 6 b) Please comment on the four factors outlined in Reference 2 for the return of \$23K recorded in
- 7 the Sub-account 1508 CCRA related to the previously disposed 2019 balance.
- 8 i) Please explain how the adjustment is reported in Reference 2.
- 9 ii) Please provide a breakdown of principal and interest, and indicate under which year it
- 10 falls.
- 11 c) Please explain the difference between the debit amount of \$1,111,627 recorded in the
- 12 Sub-account 1508 CCRA for the year 2020 transactions and the principal balance of \$1,064K
- 13 for the year 2020 as reported in Table 7 of Reference 1.
- 14 d) Please confirm and explain the variances calculated by the OEB staff and update the DVA
- 15 Workform if necessary.
- 16 e) Please confirm whether Hydro Ottawa will continue reporting amounts in the following four
- 17 sub-accounts outlined in the accounting order as approved in its last CIR application:
- 18 1. Account 1508 – SA CCRA – Depreciation
- 19 2. Account 1508 – SA CCRA – Interest
- 20 3. Account 1508 – SA CCRA – Return
- 21 4. Account 1508 – SA CCRA – PILs
- 22 i) If confirmed, please update the draft accounting order accordingly to reflect the
- 23 sub-accounts.
- 24 ii) If not confirmed, please provide an explanation.

25
26

27 **RESPONSE(S):**

28
29
30

- a) i) The A6R invoice and the refund received from Hydro One in 2022 is related to a construction cost reconciliation to the payment made in 2019.

- 1 ii) Please refer to Attachment 2-Staff-87(D) - Executed A6R CCRA included in the
2 response to interrogatory 2-Staff-87 for executed agreements between Hydro Ottawa
3 and Hydro One-REDACTED.
4
- 5 iii) Please refer to the following attachments in the interrogatory response in 2-Staff-87 for
6 Hydro One invoices and calculations:
7
 - 8 ● Attachment 2-Staff-87 (U) - A6R DCF Model
 - 9 ● Attachment 2-Staff-87 (V) - A6R Actual Cost Reconciliation Letter
 - 10 ● Attachment 2-Staff-87(W) - A6R Credit Invoice
- 11 iv) For A6R the invoice was not due to reduced or unrealized load. It was due to actual
12 construction cost reconciliation as mentioned in part (a) (i) above.
13
- 14 b) Please note this Group 2 Account is not a pass through Account. The intent of this variance
15 account is to recognize the unpredictable nature of CCRA payments.
16
- 17 i) If however Reference 2 should be applied, the OEB provides the following items to
18 determine it on a case-by-case basis whether to make a retroactive adjustment based
19 on the particular circumstances of each case, including factors such as:
20
 - 21 1. whether the error was within the control of the distributor
 - 22 2. the frequency with which the distributor has made the same error
 - 23 3. failure to follow guidance provided by the OEB
 - 24 4. the degree to which other distributors are making similar errors
- 25 Hydro Ottawa received the invoice from Hydro One related to a 2019 CCRA as well as a
26 refund from Hydro One, as a result it falls under factor 1, as it was out of the control of Hydro
27 Ottawa. It is also beneficial to the customer since it is a return to the rate payers.

1 ii) The 2019 principal amount is \$(22,783). The interest breakdown is as follows:

- 2 • 2020 \$(312.26)
- 3 • 2021 \$(129.85)
- 4 • 2022 \$(438.53)
- 5 • 2023 \$(1,149.82)
- 6 • 2024 \$(1,149.82)

7
 8 c) Hydro Ottawa received an invoice from Hydro One related to a 2020 CCRA as well as a refund
 9 from Hydro One for \$48k. Hydro Ottawa has recorded a return of \$48K (principal balance) to
 10 rate payers in this account, and, as a result, Hydro Ottawa is seeking to clear the principal
 11 balance of \$1,064K (\$1,111,627 minus \$48K) for the year 2020 as part of this Application.

12
 13 d) Hydro Ottawa has recreated Table A as requested by OEB staff. The below table shows no
 14 variances when transactions are reported in the year to which they relate. However the yearly
 15 balances listed in the Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account,
 16 submitted April 28, 2025, reflect the year they were recorded and those balances align with the
 17 RRR Reporting. The only change in the updated Deferral and Variance Account Continuity
 18 Schedule in the response to interrogatory 1-Staff-1 is to reflect 2024 actual amounts; balances
 19 from periods prior to 2024 remain unchanged. The variances are due to Reference 1 being
 20 rounded to the thousands, but the DVA Continuity Schedule (Reference 3) is not.

21

22 **Table A - Variance between Reference 3 and Reference 1**

Year	Ref. 3 - Transactions	Ref. 3 - Principal Adjustments	Ref. 3 -Total Adjusted Principal Transactions	Ref. 1 – CCRA Revenue Requirement Calc.	Rounding Variances
	A.	B.	C = (A+B)	D	(C-D)
2021	\$ (263,730)	\$ (44,293)	\$ (308,023)	\$ (308,000)	\$ (23)
2022	\$ (1,508,337)	\$ 482,736	\$ (1,025,601)	\$ (1,026,000)	\$ 399
2023	\$ (119,723)	\$ (153,772)	\$ (273,495)	\$ (273,000)	\$ (495)
Total	\$ (1,891,790)	\$ 284,671	\$ (1,607,119)	\$ (1,607,000)	\$ (119)

23

- 1 e)
 2 i) Hydro Ottawa confirms it will continue reporting amounts in the following four sub-accounts
 3 outlined in the accounting order as approved in its last Custom IR application. The draft
 4 accounting order has been updated accordingly. The description in parts A) and B) are
 5 unchanged and Table 10 from Schedule 9-1-3 - Group 2 Accounts has been expanded to
 6 include the four sub-accounts to the CCRA 1508 sub-accounts.
 7

Account	Debit	Credit
Account 1508 - Sub-Account CCRA - Depreciation	x,xxx.xx	
Account 1508 - Sub-Account CCRA - Interest	x,xxx.xx	
Account 1508 - Sub-Account CCRA - Return	x,xxx.xx	
Account 1508 - Sub-Account CCRA - PILS	x,xxx.xx	
Account 4080 – Distribution Services Revenue		x,xxx.xx
To record revenue requirement difference as actual CCRA payments are higher than forecasted		
Account 1508 - Sub-Account CCRA	x,xxx.xx	
Account 6035 - Other Interest Expense		x,xxx.xx
To record carrying charges		

- 8
 9 ii) Please see response to part (i)

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

9-Staff-206

EVIDENCE REFERENCE:

Ref. 1: Exhibit 9 / Tab 1 / Schedule 3 / pp. 17-27 (pdf pp. 27-37)

Ref. 2: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

Ref. 3: EB-2019-0261, Settlement Proposal, December 11, 2020 / Attachment 6 Accounting Order, pp. 5-6

Preamble:

In the accounting order for the CVA as provided in Reference 3, this sub-account is “an asymmetrical account, in that overspending or faster pace of spending will not result in recording debits in this account. Overspending or earlier spending will therefore not result in recording amounts to be recovered from customers during the 2021-2025 period.” Additionally, Hydro Ottawa has provided the following sample journal entry as part of the draft accounting order.

Table 15 - 1508 Sub- Account CVA Sample Journal Entry to collect additional revenue requirement

Account	Debit	Credit
Account 1508 - Sub-Account CVA XXX	x,xxx.xx	
Account 4080 – Distribution Services Revenue		x,xxx.xx
To record revenue requirement difference as cumulative capital additions are higher than forecasted		
Account 1508 - Sub-Account CVA XXX	x,xxx.xx	
Account 6035 - Other Interest Expense		x,xxx.xx
To record carrying charges		

1 OEB staff has compiled the variances between the amounts recorded in the Capital Variance
 2 Account in Reference 2 and the amounts outlined in Table 11 of Reference 1 in the table below.

3

Sub-account CVA	A. Ref. 2 - Transactions	B. Ref. 2 -Principal Adjustments	C. Ref. 2 -Total Adjusted Principal Transactions (A+B)	D. Ref. 1, Table 11 - Total Principal	Variance (C-D)
2021	30,483		30,483	1,670,000	(1,639,517)
2022	(559,111)	-	(559,111)	(1,585,000)	1,025,889
2023	41,224	(64,863)	(23,639)	(637,000)	613,361
Total	(487,405)	(64,863)	(552,268)	(552,000)	(268)

4

5 QUESTION(S):

6

7 a) Please confirm and explain the variances calculated by the OEB staff.

8 i) Please update Reference 2 if necessary.

9 b) Please provide a detailed CCA schedule supporting the CCA amounts presented in Tables 12 –
 10 14, broken down by accounts.

11 f) Please confirm whether Hydro Ottawa will continue reporting amounts in the following four
 12 sub-accounts outlined in the accounting order as approved in its last CIR application:

13 1. Account 1508 – SA SR/SS Capital Additions – Depreciation

14 2. Account 1508 – SA SR/SS Capital Additions – Interest

15 3. Account 1508 – SA SR/SS Capital Additions – Return

16 4. Account 1508 – SA SR/SS Capital Additions – PILs

17 i) If confirmed, please update the draft accounting order accordingly to reflect the
 18 sub-accounts.

19 ii) If not confirmed, please provide an explanation.

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RESPONSE(S):

Hydro Ottawa notes that there were no questions labelled parts c) to e). Hydro Ottawa also would like to note that in the accounting order for the CVA as provided in Reference 3, there are two sub-accounts: an asymmetrical account, detailed on P.5 and 6 and a symmetrical account, detailed on P.7 and 8.

a) The attachment noted in reference 2 has been updated, please refer to Attachment 1-Staff-1(C) - OEB_Workform - 2026 DVA_Continuity_Schedule. Hydro Ottawa has created a modified version of the OEB-Staff table included in the preamble. Table A below shows no variances when transactions are reported in the year to which they relate. However the yearly balances listed in the Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account, April 28, 2025 reflect the year they were recorded and those balances align with the RRR Reporting. The only change in the updated Deferral and Variance Account Continuity Schedule in 1-Staff-1 is to reflect 2024 actual amounts; balances from periods remain unchanged. The only variance is due to Reference 1 being rounded to the thousands, but the DVA Continuity Schedule (Reference 2) is not.

Table A - Variance between Reference 2 and Reference 1

Year	Ref. 2 - Transactions	Ref. 2 - Principal Adjustments	Ref. 2 -Total Adjusted Principal Transactions	Ref. 1, Table 11 - Total Principal (System Access - Sub)	Ref. 1, Table 11 - Total Principal (System Access)	Ref. 1, Table 11 - Total Principal (General Plant)	Ref. 1, Table 11 - Total Principal	Rounding Variance
	A.	B.	C = (A+B)	D.	D.	D.	Sum of D	(C-D)
2021	\$ 30,483	\$ 526,091	\$ 556,574	\$ 94,000	\$ (60,000)	\$ 522,000	\$ 556,000	\$ 574
2022	\$ (559,111)	\$ (590,458)	\$ (1,149,570)	\$ 609,000	\$ (600,000)	\$ (1,159,000)	\$ (1,150,000)	\$ 430
2023	\$ 41,224	\$ (495)	\$ 40,729	\$ 966,000	\$ (925,000)	-	\$ 41,000	\$ (271)
TOTAL	\$ (487,405)	\$ (64,862)	\$ (552,267)	\$ 1,670,000	\$ (1,585,000)	\$ (637,000)	\$ (553,000)	\$ (733)

- 1 i) The Deferral and Variance Account Continuity Schedule was updated in 1-Staff-1 to
 2 reflect 2024 actuals. There are no further updates needed to the DVA Continuity
 3 Schedule for the CVA Variance account.
 4
- 5 b) Please see Tables B, C and D below to support the CCA amounts presented in Tables 12 to 14
 6 of Schedule 9-1-3 - Group 2 Accounts and Attachments 9-Staff-206(A) - CCA Schedule for GP,
 7 9-Staff-206(B) - CCA Schedule for System Access and 9-Staff-206(C) - CCA Schedule for
 8 Residential & PR for the detailed CCA Schedule for General Plant, System Access additions
 9 (excluding Residential & Plant Relocation) and System Access additions (Residential & Plant
 10 Relocates) .
 11

12 **Table B – Difference in CCA for General Plant additions between OEB Approved Final**
 13 **Settlement and Actual Additions for 2021 - 2023 Historical Years**

Year	Final Settlement CCA	Actual CCA	Difference in CCA
2021	\$8,014	\$3,534	\$ 4,480
2022	\$7,306	\$6,576	\$ 730
2023	–	–	–

14
 15
 16 **Table C – Difference in CCA for System Access additions (excluding Residential & Plant**
 17 **Relocation) between OEB Approved Final Settlement and Actual Additions for 2021 - 2023**
 18 **Historical Years**

Year	Final Settlement CCA	Actual CCA	Difference in CCA
2021	1,597	\$863	\$ 734
2022	\$2,227	\$1,393	\$834
2023	\$2,870	\$1,739	\$1,131

19

1 **Table D – Difference in CCA for System Access additions (Residential & Plant Relocates)**
2 **between OEB Approved Final Settlement and Actual Additions for 2021 - 2023 Historical**
3 **Years**

Year	Final Settlement CCA	Actual CCA	Difference in CCA
2021	\$747	\$ 1,503	(\$756)
2022	\$1,298	\$2,259	(\$961)
2023	1,771	\$3,087	(\$1,316)

4
5
6 f)

7 i) Hydro Ottawa confirms that it intends to continue reporting amounts using the four sub
8 accounts. The Accounting Order will remain the same as Reference 3 with the exception of
9 the proposed changes outlined in Schedule 9-1-3 and Schedule 9-2-1.

10
11 ii) Please see response to part i)

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-207**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 3 / pp. 20, 22, 24 (pdf pp. 30, 32, 34)

8 Ref. 2: EB-2019-0261, Settlement Proposal, September 18, 2020

9
10 **QUESTION(S):**

11
12 a) For Tables 12, 13, 14, please provide the data and calculations to support the amounts in the
13 “(Under)/Over additions” row, including at a minimum the approved amounts from reference 2,
14 and the actual amounts.

15
16 _____
17 **RESPONSE(S):**

18
19 a) Please refer to Attachment 9-Staff-207(A) - Under/Over Additions for the data and calculations
20 to support the amounts in the “(Under)/Over additions”. For Table 12, please see Tab “GP, no
21 CCRA”. For Table 13, please see Tab “SA Other”. For Table 14, please see Tab “SA Resi &
22 PR”.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-208**

4
5 EVIDENCE REFERENCE:

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 3 / pp. 29-31 (pdf pp. 39-41)

8 Ref. 2: Exhibit 9 / Tab 3 / Schedule 1 / p. 3 (pdf p. 86)

9 Ref. 3: 2021 OEB Custom Incentive Rate Progress Report / pp. 12-14

10 Ref. 4: 2022 OEB Custom Incentive Rate Progress Report / pp. 12-14

11 Ref. 5: 2023 OEB Custom Incentive Rate Progress Report / pp. 12-14

12 Ref. 6: EB-2019-0261, Settlement Proposal, September 18, 2020 / Attachment 5 / pp. 3-5

13
14 Preamble:

15 In Reference 6, the thresholds for Metrics #3, #4 and #5 are stated to be:

16 Yellow >Target <5% above target

17 Red ≥ 5% above target

18
19 The 2021, 2022 and 2023 reports (references 3-5) show the thresholds for Metrics #3, #4 and #5
20 as:

21 Yellow >Target <105% target

22 Red ≥ 105% target

23
24 QUESTION(S):

25
26 a) Please confirm the Hydro Ottawa Annual reports in references 3, 4 and 5 should say the results
27 are “red” if the actual value is equal to or greater than 5% more than the target.

28 b) Please confirm that the actual SAIDI results, i.e. the metric shown in Table 8 – Metric #3, for
29 2022 and 2023, have been classified as Red.

30 i) If confirmed, will Hydro Ottawa post a corrected version of the 2023 report on its website
31 and resubmit a corrected version of the report to the OEB?

- 1 ii) If not confirmed, please reconcile the information regarding the Performance Outcomes
2 Accountability Mechanism (POAM) deferral account in references 1 and 2.
3

4

5 **RESPONSE(S):**

6

7 Preamble: a result that is \geq 105% target is the same as a result that is \geq 5% above target

8

9 a) Hydro Ottawa confirms results for references 3, 4 and 5 in Hydro Ottawa Annual reports are
10 “red” if the actual value is equal to or greater than 5% more than the target Future annual OEB
11 Custom Incentive Rate Progress Reports will match the wording for the thresholds as found in
12 EB-2019-0261, Settlement Proposal, September 18, 2020.

13

14 b) Hydro Ottawa confirms for years 2022-2023 Hydro Ottawa did not meet two POAM targets,
15 those being (1) SAIDI - Excluding Major Event Days and Loss of Supply (Table 8 - Metric #3)
16 and (2) Wood Pole Replacement Unit Cost (Table 9 - Metric #4). Metric #3 and metric #4 are
17 classified as “red” for 2022 and 2023.

18

- 19 i) As stated in footnote 1 in the 2023 OEB Custom Incentive Rate Progress Report,
20 adjustments to prior year reporting will be completed on a go forward basis and may
21 result in differences between previous CIR reports. Hydro Ottawa will correct the 2022
22 and 2023 results in Table 8 - Metric #3 in the 2024 OEB Custom Incentive Rate Progress
23 Report submission to the OEB. The corrected results will be updated on Hydro Ottawa’s
24 website at that time.
- 25

- 26 ii) Please see response to part b) i).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

9-Staff-209

EVIDENCE REFERENCE:

Ref. 1: Exhibit 9 / Tab 1 / Schedule 3 / p. 30 (pdf p. 40)

Ref. 2: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

OEB staff has compiled the variances between the amounts recorded in the Sub-account POAM in Reference 2 and the annual credit of \$400K recorded in 2022 and 2023 as stated in Reference 1 in the table below.

Sub-account POAM	A. Ref. 2 - Transactions	B. Ref. 1	Variance (A-B)
2021	(107,638)	-	(107,638)
2022	(292,362)	(400,000)	107,638
2023	(400,000)	(400,000)	-
Total	(800,000)	(800,000)	0

QUESTION(S):

- a) Please reconcile and explain the differences calculated by OEB staff.
- b) Please update the DVA Workform if necessary.

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RESPONSE(S):

a) On December 31, 2021, an error was made in the entry to the POAM Deferral Account. The entry recorded a charge of \$(107,638) because it appeared that Metric #4 (cost per pole) had not been met. The initial calculation showed the 2021 actual cost per pole to be \$8,739, which was higher than the target of \$8,510.

However, in 2022, an error was discovered in the original calculation. The denominator used for the number of poles was incorrect. After correcting this, the revised 2021 cost per pole was determined to be \$8,415, which is below the \$8,510 target. Consequently, the original \$(107,638) charge was reversed.

Hydro Ottawa has recreated Table A as requested by OEB staff. The below table shows no variances when transactions are reported in the year to which they relate. However the yearly balances listed in the Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account, April 28, 2025 reflect the year they were recorded and those balances align with the RRR Reporting. The only change in the updated Deferral and Variance Account Continuity Schedule in 1-Staff-1 is to reflect 2024 actual amounts; balances from periods prior to 2024 remain unchanged.

Table A - Variance between Reference 2 and Reference 1

Year	Ref. 2 - Transactions	Ref. 2 - Principal Adjustments	Ref. 2 -Total Adjusted Principal Transactions	Ref. 1	Variance
	A.	B.	C = (A+B)	D	(C-D)
2021	\$ (107,638)	\$ 107,638	-	-	-
2022	\$ (292,362)	\$ (107,638)	\$ (400,000)	\$ (400,000)	-
2023	\$ (400,000)	-	\$ (400,000)	\$ (400,000)	-
TOTAL	\$ (800,000)	-	\$ (800,000)	\$ (800,000)	-

- 1 b) No change was required as a result of this interrogatory response, however please note the
- 2 Deferral and Variance Account Continuity Schedule was updated in 1-Staff-1. Please refer to
- 3 Attachment 1-Staff-1(C) - OEB_Workform - 2026 DVA_Continuity_Schedule.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-210**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: EB-2023-0143, Decision and Order, Getting Ontario Connected Act Variance Account,
8 October 31, 2023

9 Ref. 2: Exhibit 9 / Tab 1 / Schedule 3 / p. 41 (pdf p. 51)

10
11 **Preamble:**

12 On October 31, 2023, the OEB issued a decision and order in EB-2023-0143 for the Getting Ontario
13 Connected Act Variance Account (GOCA variance account). The decision states as follows:

14
15 “The OEB notes that the GOCA variance account will only be available to a utility until the end of its
16 current IRM period. The account is not available for utilities that have reflected Bill 93 in their most
17 recent rebasing applications.”

18
19 In Reference 2, Hydro Ottawa stated that it “will continue to track the variance between locate costs
20 resulting from Bill 93 and the approved cost included in base rates for 2024 and 2025.”

21
22 **QUESTION(S):**

23
24 a) Please confirm that the OM&A cost in the test year reflects the Bill 93 impact for the utility’s
25 locate cost.

26 i) If so, please confirm whether the GOCA variance account will be discontinued starting in
27 2026 and beyond.

28 ii) If not, please provide the rationale why the Bill 93 impact is not reflected in the test
29 year’s OM&A cost.

30

1

2 **RESPONSE(S):**

3

4 a) Hydro Ottawa confirms that the OM&A cost in the Test Year reflects the forecasted Bill 93
5 impact for the utility's locate cost.

6

7 i) The GOCA will discontinue effective December 1, 2026. As noted, Hydro Ottawa will
8 continue to track the variance between locate costs resulting from Bill 93 and the
9 approved cost included in base rates for 2024 and 2025, as these two years are prior to
10 the rebasing year, as well as not part of the Original evidence submitted.

11

12 Please refer to the interrogatory response to 1-Staff-1 for an updated Deferral and
13 Variance Account Continuity Schedule with the inclusion of 2024 balances. The 2025
14 variance has not been calculated and will be completed as part of a future application.
15 As a result, the GOCA Variance Account will continue until the next rebasing application
16 until disposition of any final amounts occur.

17

18 ii) Please see response to part a) i).

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-211**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 2 / Schedule 1 / p. 4 (pdf p. 79)

8 Ref. 2: Exhibit 3 / Tab 1 / Schedule 1 / p. 10 (pdf p. 10)

9
10 **Preamble:**

11 Hydro Ottawa states the Large Load Revenue Variance Account would “manage discrepancies
12 between predicted large load requests as outlined in Table 8 of Schedule 3-1-1 - Revenue Load and
13 Customer Forecast and actual billed demand for these large load requests.”

14
15 **QUESTION(S):**

16
17 c) Please explain what impact variances between the actual loads realized and forecast loads in
18 Table 8 for 2024 and 2025 will have for the purposes of the Large Load Variance Account.

19 i) Will the values for 2026 through 2030 be updated with a revised load forecast using
20 2024 actuals?

21
22
23 **RESPONSE(S):**

24
25 Please note there is no part (a) or (b) to this question.

26
27 c) The Large Load Revenue Variance Account is designed to track revenue variances between
28 forecast and actual billed demand specifically for the large load requests outlined in Table 8 of
29 Schedule 3-1-1 - Revenue Load and Customer Forecast. To clarify, Table 8 shows the impact of
30 large load requests and commercial LDEV. The large load revenue variance account will
31 exclude the variance related to commercial LDEV.

1 For 2024 and 2025, variances between actual loads realized and forecast loads in Table 8 will
2 not impact the Large Load Revenue Variance Account because this account is only effective
3 starting January 1, 2026. The account is being established specifically for the 2026-2030 rate
4 period.

5
6 Once established in 2026, the account will track both volume and timing variations between
7 forecast and actual demand for these large load requests. It will only capture variances for the
8 period until the load materializes, and should load materialize at a larger amount, the account
9 will also capture the impacts of additional revenue. Hydro Ottawa will commence recording into
10 this variance at the earlier of project energized date vs actual energization date of the facilities.
11 The variance account will be net of any adjustment in customer contributions. The cumulative
12 balance in this account from 2026-2029 will be put forward for disposition in Hydro Ottawa's
13 next rebasing application, while the 2030 balance will be disposed of according to OEB
14 guidelines for Group 2 Accounts.

15
16 i) Hydro Ottawa has not proposed to provide a revised load forecast using 2024 actuals.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-212**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 4 / pp. 2-3 (pdf pp. 55-56 of)

8 Ref. 2: 2020 Accelerated CCA for CCRA, April 28, 2025

9 Ref. 3: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

10
11 **Preamble:**

12 In Reference 1 Table 1, Hydro Ottawa outlined the impact of prior “regular” CCA rules vs.
13 Accelerated CCA rules on CCRA for 2020. Hydro Ottawa stated that no balance is required past
14 2020 as Accelerated CCA for CCRA payments were reflected in the base rates for the 2021 – 2025
15 rate years in Hydro Ottawa’s 2021-2025 Approved Settlement Agreement.

16
17 **QUESTION(S):**

18
19 c) Please confirm whether the AIIP addition of \$520K reported in Reference 2 is the total AIIP
20 addition in 2020 for CCRA.

21 i) Please explain and reconcile the AIIP addition of \$520K and the 2021 transaction
22 amount of \$1,111,627 reported in Account 1508, CCRA Payment Differential Variance
23 Account in Reference 3.

24 d) Please explain why the “regular” CCA under the legacy CCA rules reported in Table 1 of
25 Reference 1 is higher than the Accelerated CCA.

26 i) Please provide the calculation for the “regular” CCA of \$504,182 under the legacy CCA
27 rules reported in Table 1 of Reference 1.

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RESPONSE(S):

Please note there is no part a) or b) to this interrogatory.

c) The \$520K represents a CCRA true-up for 2020 and should not have been included in the schedule, April 28 - Attachment 9-1-4(A) - 2020 Accelerated CCA for CCRA as an addition for 2020.

i) Given the response above to question c), no reconciliation between the AIPP addition of \$520K and the 2021 transaction amount of \$1,111,627 reported in Account 1508, CCRA Payment Differential Variance Account in Reference 3 is required.

d) The regular CCA of \$504,182 under the legacy CCA rules as reported in Table 1 in Schedule 9-1-4 - Account 1592 PILS and Tax Variance is higher than the Accelerated CCA because the 2019 CCRA additions had a portion of the 2019 additions eligible for Accelerated CCA in 2019. As previously described in Schedule 6-2-1 - Payments in Lieu of Taxes, section 6, accelerated CCA does not change the total amount of CCA that Hydro Ottawa can deduct over the tax life of the eligible capital assets. However, accelerated CCA is only available to be claimed in the first tax year that the eligible capital assets are acquired and available for use. By claiming a larger CCA deduction in the first year, Hydro Ottawa will have smaller CCA deductions available in future years. Correspondingly, the CCA deduction for the portion of 2019 CCRA additions eligible for accelerated CCA in 2019 is less in 2020.

i) Please see Attachment 9-Staff-212(A) - Original Regular CCA Schedule for the calculation of “regular” CCA of \$504,182 for 2020. However, please note that the calculations for “regular” CCA for 2020 has been revised and the “regular” CCA for 2020 has been revised to \$481,432. Further details about these revisions for 2020 are described in the following paragraphs.

1 Hydro Ottawa has updated the 2020 “regular” CCA and accelerated CCA calculation for 2020
 2 CCRA additions. In the original Table 1 in Schedule 9-1-4 - Account 1592 PILS and Tax
 3 Variance and the related CCA calculations, Hydro Ottawa included in error \$910K as an addition
 4 in 2020 for the regular CCA calculation. Hydro Ottawa also included in error \$520K as an
 5 addition in 2020 for the accelerated CCA calculation. The \$910K addition for 2020 in the regular
 6 CCA calculation was an estimate used in an illustrative example during the 2021-2025 Rate
 7 Application¹, as this portion of the PILS regulatory account is to record actuals related to the
 8 CCRA variance account, it should not have been included. The \$520K represents a CCRA
 9 true-up for 2020 and this amount should not have been included as an addition in the
 10 accelerated CCA calculations for CCRA in 2020 as true-up were only included starting 2021.

11
 12 The difference in grossed up PILs for 2020 of \$2,393 has been updated in Table A. For the
 13 regular CCA calculation, the 2020 addition for CCRA has been revised to \$nil instead of \$910K,
 14 because \$910K was only an estimate used at that time. For the accelerated CCA calculation the
 15 2020 addition for CCRA has also been revised to \$nil because the \$520K is not an addition but
 16 a true-up for CCRA. Both the revised regular CCA calculation of \$481,432 and the revised
 17 accelerated CCA calculation of \$474,796 for 2020 can be found in Attachments 9-Staff-212(B) -
 18 Revised CCA Schedule Not Accelerated and 9-Staff(C) - Revised CCA schedule Accelerated,
 19 respectively. Both CCA calculations are based on \$nil additions for CCRA for 2020.

20
 21 **Table A – UPDATED Impact of Prior “Regular” CCA Rules vs. Accelerated CCA Rules on**
 22 **CCRA for 2020**

Year	REVISED “Regular” CCA	REVISED Accelerated CCA	REVISED Difference in CCA	REVISED Difference in Grossed Up PILS
2020	\$ 481,432	\$ 474,796	\$ (6,636)	\$ 2,393

23

¹ Hydro Ottawa Limited, *2021-2025 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2019-0261 (February 10, 2020).

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-213**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 4 / pp. 4-11 (pdf pp. 57-64)

8 Ref. 2: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

9 Ref. 3: EB-2019-0261, Draft Rade Order, December 11, 2020 / Deferral and Variance Account
10 Continuity Schedule

11
12 Preamble:

13 Table 2 in Reference 1 outlines the impact of 2021 immediate expensing for 2021 – 2025.

14
15 OEB staff has summarized the amounts recorded in Account 1592, sub-account CCA Changes, as
16 reported in Reference 2, in the table below.

1

Account 1592, Sub-account CCA Changes	Transactions	Principal Adjustments	Interests (incl. Adjustments)	Total
Opening Balance	-	-	-	-
2020	-	-	-	-
2021	-	50,067	2,392	52,459
2022	-	-	-	-
2023	(873,859)	8,982	(41,684)	(906,561)
Projected Interest on Dec. 31, 2023			(71,566)	(71,566)
Total Claim	\$ (873,859)	\$ 59,049	\$ (110,857)	\$ (925,668)

2

3 Table 5 in Reference 1 provides a reconciliation to Account 1592, Sub-account CCA Changes at the
 4 end of 2023.

5

6 QUESTION(S):

7

8 a) Please provide a detailed CCA schedule supporting the CCA amounts (both under legacy CCA
 9 rules and the Immediate Expensing CCA rules) presented in Table 2 of Reference 1, broken
 10 down by account for 2021 - 2025.

11 b) Please confirm whether the CCA impact of \$ 476K presented in Table 2 of Reference 1 is
 12 included in the balance of the proposed PILs Contribution and the Other Expenses in the
 13 proposed Revenue Requirements.

- 1 i) Please provide the rationale for smoothing the amounts recorded in Sub-account, CCA
2 Changes related to the Immediate Expensing impact for 2021 – 2023, particularly given
3 that the impact for 2024 and 2025 offsets half of the impact from 2021 – 2023.
- 4 c) Please update Reference 2 to ensure that the amounts for each year presented in Table 5
5 correspond accurately to the respective year. Also, please update the interest amounts in
6 Reference 2 accordingly.
- 7 d) Please update Reference 2 to ensure that the opening balance is aligned with the balance
8 recorded in Reference 3.
- 9
- 10

11 **RESPONSE(S):**

12

- 13 a) Please see Attachments 9-Staff-213(A) - CCA Schedule for 2021-2025 Regular and
14 9-Staff-213(B) - CCA Schedule or 2021-2025 Immediate Expensing for the 2021 - 2025 CCA
15 schedules for both legacy “regular” CCA rules and the Immediate Expensing CCA rules
16 presented in Table 2 in Schedule 9-1-4 Account 1592 PILS and Tax Variance.
- 17

- 18 b) Confirmed.

- 19 i) Please refer to p.8 of Schedule 9-1-4 Account - 1592 PILS and Tax Variance. The intent
20 of the proposed treatment of immediate expensing is to spread the accumulated impact
21 across current and future generations of rate payers by associating the tax benefit with
22 the assets they pertain to, and not providing the immediate tax benefit to existing
23 customers from assets that will be paid for by current and future rate payers over an
24 extended period of time.
- 25

26 Although the 2024-2025 impact offsets approximately half the benefit, a benefit balance
27 of \$476,000 remains that will benefit the rate payer starting after 2025. In addition, by
28 reducing ratebase it also reduces the cost of capital embedded into rates. Lastly, the
29 government may be contemplating introducing new immediate expensing rules which
30 would increase the overall benefit.

1 c) Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account, April 28, 2025 (Reference
 2 2) was provided as part of the updated evidence. The only change in the updated Deferral and
 3 Variance Account Continuity Schedule in 1-Staff-1 is to reflect 2024 actual amounts; balances
 4 from periods prior to 2024 remain unchanged. Hydro Ottawa has recreated Table A as
 5 suggested by OEB staff. Note the yearly balances listed in the Attachment 9-3-1(A) - OEB
 6 Workform Deferral and Variance Account, April 28, 2025 reflect the year they were recorded and
 7 the balances submitted as part of Hydro Ottawa's RRR Reporting.

8

9 **Table A - Updated amounts recorded in Account 1592, sub-account CCA Changes**

Year	Transactions	Principal Adjustments	Interest (incl. Adjustments)	Total
Opening Balance				
2020	\$ 2,393			\$ 2,393
2021	-	\$ (378,571)	\$ 14	\$ (378,557)
2022	-	\$ (260,125)	\$ (7,241)	\$ (267,366)
2023	\$ (873,859)	\$ 694,702	\$ (32,114)	\$ (211,271)
2024	\$ 251,731	\$ (56,657)	\$ (41,940)	\$ 153,134
Projected Interest on Dec 31, 2024			\$ (19,557)	\$ (19,557)
Total Claim	\$ (619,735)	\$ (651)	\$ (100,838)	\$ (721,224)

10

11

12 d) Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account, April 28, 2025 (Reference
 13 2) was updated. Please see Attachment 1-Staff-1(C) OEB_Workform - 2026
 14 DVA_Continuity_Schedule). The opening balance is aligned with the balance recorded in
 15 Reference 3.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-214**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 4 / p. 9 (pdf p. 62)

8 Ref. 2: Hydro Ottawa 2026-2030 PIL Tax Model, Tab H1, June 4, 2025

9
10 Preamble:

11 In Reference 1, Hydro Ottawa proposed to “exclude the impact of the decrease in Grossed Up PILs
12 due to Accelerated CCA for 2026 and 2027 and the impact of the decrease in accumulated Grossed
13 Up PILS due to the 2021 immediate expensing measure in the proposed revenue requirement for
14 2026 and 2027.” The difference in grossed up PILs is provided in Table 3.

15
16 Hydro Ottawa proposed to record a corresponding amount in the fixed asset subledger (similar to
17 Capital Contributions) and amortize these amounts over 36 years.

18
19 The amounts added to 2026 and 2027 proposed revenue requirements and set up as PILs
20 Contribution are outlined in the Table 4 of the reference 1.

21
22 OEB staff notes that the test year additions that are accelerated investment incentive properties
23 (AIIP) reported in Reference 2 for 2026 and 2027 are \$204,328,417 and \$276,568,422. These
24 additions are different from those reported in Table 3 in Reference 1.

25
26 OEB staff further notes that the total grossed up PILs difference included in the Revenue
27 Requirement provided in Table 4 for both years differs from those reported in the 2026 and 2027
28 Revenue Requirement Workforms. The variances are summarized in a table below.

1

	2026	2027
A: Table 4 -Total Grossed Up PILs Difference Included in Revenue Requirement	\$5,066,000	\$4,096,000
B: Other Expenses Reported in Revenue Requirement Workform	\$4,590,474	\$4,596,313
Variances (A-B)	\$475,526	(500,313)

2

3 QUESTION(S):

4

5 a) Please explain and reconcile the following variances observed by the OEB staff:

6 i) The variances in the AIIP additions as reported in both references.

7 ii) The variances in total grossed up PILs difference included in revenue requirement
 8 reported in Table 4 and those reported in the 2026 and 2027 Revenue Requirement
 9 Workforms.

10 b) Please provide a detailed CCA schedule supporting the CCA amounts presented in Tables 3
 11 and 4, broken down by account for 2026 and 2027.

12 c) Please provide the rationale for determining the amortization period of 36 years for the
 13 proposed "PILs Capital Contribution."

14 d) Please explain why Hydro Ottawa proposes smoothing out the AIIP impact for the final two
 15 years of the accelerated CCA impact now, particularly given that the Custom IR specifies the
 16 revenue requirement for each individual test year from 2026 to 2030.

17 i) What is the justification for addressing the AIIP impact outside of the derivation of the
 18 PILs?

19 ii) Is Hydro Ottawa aware of any precedent case where a similar smoothing mechanism
 20 (i.e., addressing the AIIP impact outside of the PILs) has been proposed?

21 e) Please confirm that a credit of \$5.066M and a credit of \$4.096M is included in Account 2440,
 22 Deferred Revenue in 2026 and 2027.

1 f) Please confirm if the amortization of the “PILs Contribution” is reported in Account 4245,
2 Government and Other Assistance Directly Credited to Income.

3
4
5 **RESPONSE(S):**

6
7 a)

8 i) Differences in fixed assets additions for tax purposes for 2026 and 2027 between PILS
9 Workform and Table 3 are due to the timing when the amounts in Table 3 of Schedule 9-1-4
10 Account 1592 PILS and Tax Variance, were initially calculated and were not updated for final
11 adjustments. A footnote should have been included in Table 3 stating that the additions for
12 2026 and 2027 were only estimates used to calculate CCA.

13
14 ii) The amounts in Table 4 - PILS Contribution of Schedule 9-1-4 are the updated amounts
15 while the amounts in Table 2 of Schedule 6-1-1 - Revenue Requirement and Revenue
16 Deficiency or Sufficiency are based on estimates. The PILs Contribution amounts for 2026
17 and 2027 will be updated to final and approved additions for 2026 and 2027 at a later stage
18 in the proceeding.

19
20 b) Please see Attachments 9-Staff-214(A) - CCA Schedule 2026 & 2027 Accelerated CCA and
21 9-Staff-214(B) - CCA Schedule 2026 & 2027 NOT Accelerated CCA for detailed supporting CCA
22 Schedules.

23
24 c) The rationale for determining the amortization period of 36 years is that 36 years represents the
25 average weighted useful life of the assets.

26
27 d) Hydro Ottawa proposes that the smoothing out of AIP (or Accelerated CCA) impact over 36
28 years allows the benefit of the PILs impact to be averaged out across generations of rate payers
29 as this proposal reduces the amount of return on capital on these investments. Please refer to
30 interrogatory response 9-Staff-213 for additional details.

- 1 i) The maximum CCA deduction is required to be reflected in the regulatory PILs calculation
2 even though CCA is a discretionary deduction for tax purposes. The only mechanism to
3 smooth the Accelerated CCA impact is for this to be external to the PILS calculation.
- 4 ii) Hydro Ottawa is not aware of any precedent case.
- 5
- 6 e) Confirmed. Please refer to the interrogatory response 1-Staff-1 for further details.
- 7
- 8 f) Not confirmed, the amortization of the “PILs Contribution” is not reported in Account 4245,
9 Government and Other Assistance Directly Credited to Income, it is included in Account 5705 -
10 Amort Exp - Prop Plant & Equip.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-215**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 2 / Schedule 1 / pp. 1-6 (pdf pp. 77 - 82)

8 Ref. 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition
9 for 2026 Rate Applications, May 7, 2025, p.68

10
11 **QUESTION(S):**

12
13 a) Please provide detailed comments on the three eligibility criteria for the establishment of a new
14 DVA as outlined in Section 2.9.2 of Reference 2 for the three proposed new DVAs provided in
15 Reference 1.

16
17
18 **RESPONSE(S):**

19
20 a) Refer to Section 3.5.3.1 Asymmetrical Sub-Accounts of Schedule 1-3-1, which outlines the three
21 eligibility criteria for the establishment of these proposed new DVA accounts.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-216**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 2 / Schedule 1 / p. 5 (pdf p. 81)

8 Ref. 2: Exhibit 1 / Tab 3 / Schedule 1 / p. 35 (pdf p. 249)

9
10 **Preamble:**

11 In reference 1, Hydro Ottawa states the Tariff Impact Deferral Account “will track costs incurred
12 during the test period directly attributable to imposed global tariffs.”

13
14 In reference 2, Hydro Ottawa states it “requests a deferral account to address the risk of tariffs from
15 supply chain disruptions and tariffs on imported components essential for Hydro Ottawa’s
16 distribution infrastructure.”

17
18 **QUESTION(S):**

- 19
20 a) Please provide a more detailed explanation of the types of items that Hydro Ottawa proposes be
21 included in the Tariff Impact Deferral Account.
- 22 b) Please elaborate on what Hydro Ottawa means by “directly attributable” in this context.
- 23 c) What constitutes “components essential for Hydro Ottawa’s distribution infrastructure”?
- 24 i) Does the request propose to include items purchased for general plant capital or OM&A
25 costs in this account, such as vehicles and IT equipment?
- 26 ii) Does the request include consulting services if tariffs are applied?

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RESPONSE(S):

a) The proposed Tariff Impact Deferral Account is designed to capture additional costs Hydro Ottawa incurs within its supply chain directly due to global tariffs. These costs, which are beyond Hydro Ottawa's control and emerged after our test year forecasts, may include:

- **Direct Tariff Duties:** These are the costs applied to imported materials and equipment purchased directly by Hydro Ottawa, which are subject to cross-border or retaliatory tariffs.
- **Increased Supplier Prices:** We anticipate higher prices for finished goods like electrical equipment, construction materials, vehicles, vehicle parts, and specialized tools. This is because our suppliers will pass on their increased costs resulting from tariffs on their raw materials.
- **Higher Contractor Service Costs:** The base prices for contractor services may also rise if their underlying costs are impacted by global tariffs.

This account will allow us to track these unpredictable and substantial tariff-driven expenses throughout the upcoming rate term.

b) When Hydro Ottawa uses the term "directly attributable" in the context of the Tariff Impact Deferral Account, it means that only those costs that are clearly and specifically linked as a direct consequence of an imposed global tariff will be included. Example of directly attributable costs include:

- Tariff duties itemized on supplier invoices.
- Documented supplier price increases citing tariff-related cost adjustments.
- Contract amendments where the change in price is supported by evidence of tariff impacts.

Essentially, "directly attributable" ensures that the deferral account only captures the precise, verifiable financial impact of tariffs, distinguishing them from other, more general business costs or risks.

- 1 c) “Components essential for Hydro Ottawa’s distribution infrastructure” refers to materials and
2 equipment, in whole or in part, that are critical to Hydro Ottawa’s distribution network. In
3 essence, everything included in the rate application, other than the costs included in Other
4 Revenue, is considered a component essential for Hydro Ottawa’s distribution infrastructure.
- 5 i. Yes, the request includes a provision for all additional expenses incurred as a result of
6 the global tariffs. Therefore, the deferral account would include the revenue
7 requirements impact of both OM&A and capital.
- 8 ii. As answered in i above, the request includes a provision for all additional expenses
9 incurred as a result of the global tariffs. However, Hydro Ottawa is actively reviewing
10 suppliers to minimize risk and considers the likelihood of incurring tariff-related
11 consulting costs to be low.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-217**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 2 / Schedule 1 / pp. 1-7 (pdf pp. 77-83)

8
9 **QUESTION(S):**

- 10
11 a) Hydro Ottawa is requesting approval of a new symmetrical variance account to record the
12 difference between forecasted and actual NWS costs in other revenue and OM&A, net of any
13 external funding related to NWS.
- 14 b) Please confirm if the account is intended to capture various uncertainties, including potential
15 external funding (like NRCan's funding for the ODERA project) as well as funding that could
16 come from the eDSM Framework. If so, please provide some examples of variances that Hydro
17 Ottawa may anticipate and explain why this variance account will best address this uncertainty.
18 Has Hydro Ottawa explored any other options to address these uncertainties?

19
20
21 **RESPONSE(S):**

22
23 Please note part a) appears to be the preamble and therefore no response has been provided.

- 24
25 b) The NWS variance account is intended to capture a range of uncertainties related to NWS
26 projects and does not include the NRCan funding for the ODERA project as detailed in Section
27 3 of Exhibit 2-5-8 - System Service Investments. For details on the rate funding requirements for
28 ODERA please refer to response to interrogatory 2-Staff-69 and response to interrogatory
29 2-SEC-54 part (b) for the detailed project estimate.

1 The NWS variance account is intended to track the differences between projected and actual
2 costs, offset by any potential external funding and utility remuneration. Please see response to
3 interrogatory 1-Staff-18 and 1-Staff-7 for more details. Hydro Ottawa anticipates variances such
4 as actual vs forecast costs beyond its control, evolving needs, policy shifts, timing and
5 availability of external funding. Hydro Ottawa views the variance account as the best
6 mechanism to address these uncertainties because it provides a transparent method to record
7 and track costs while ensuring progress in NWSs. It allows Hydro Ottawa to proceed with the
8 immediate deployment of NWS projects to address critical system needs without having to wait
9 for external funding mechanisms to be finalized, thereby preventing unnecessary project delays.
10 The account is also designed with symmetry, meaning it can result in funds being returned to
11 customers if forecast spending is less than anticipated. This mechanism ensures that
12 ratepayers are also protected, while allowing for the pursuit of innovative solutions. The primary
13 alternative was to delay the deployment of NWS projects until the availability of external funding
14 mechanisms was confirmed but this was rejected as it could act as a disincentive to pursuing
15 innovative, capital deferring solutions.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-218**

4
5 EVIDENCE REFERENCE:

6
7 Ref. 1: Exhibit 9 / Tab 1 / Schedule 5 / p. 1 (pdf p. 66)

8 Ref. 2: HOL_Attachment 9-1-5(A) - OEB LRAMVA Workform_20250415.xlsx

9 Ref. 3: HOL_Attachment 9-3-1(A) - OEB Workform Deferral and Variance Account (Continuity
10 Schedule)_20250415.xlsx

11 Ref. 4: 2021 Conservation and Demand Management Guidelines for Electricity Distributors (CDM
12 Guidelines)

13 Ref. 5: EB-2024-0118, Non-wires Solutions Guidelines for Electricity Distributors, March 28, 2024
14 (NWS Guidelines)

15
16 Preamble:

17 In the 2021 CDM Guidelines, the use of LRAMVA is no longer the default approach for CDM
18 activities once the CFF wind-down is complete.

19
20 There appears to be a discrepancy in the LRAMVA amount proposed for disposition by Hydro
21 Ottawa between references:

- 22 • The LRAMVA balance per the OEB LRAMVA Workform is \$(633,668).
23 • The LRAMVA balance per Exhibit 9-1-5, as well as the OEB Workform Deferral and
24 Variance Account (Continuity Schedule), is \$(684,997).

25 The difference appears to be in the calculation of carrying charges (where interest can be
26 calculated on the LRAMVA balance until the time of intended disposition):

- 27 • Carrying charges were calculated until December 31, 2025, in Exhibit 9-1-5 and the OEB
28 Workform Deferral and Variance Account (Continuity Schedule), amounting to \$(100,730).
29 • Carrying charges were calculated until Q4 2023 in the OEB LRAMVA Workform amounting
30 to \$(49,402).

31 The principal amount is consistent between all three references at \$(584,266).

1 Hydro Ottawa also indicates it will calculate the impact of CDM savings for the years 2024 to 2025
2 in the LRAMVA once the IESO releases reports of those years.

3

4 **QUESTION(S):**

5

- 6 a) Please confirm the LRAMVA amount Hydro Ottawa is requesting for disposition.
- 7 b) Please update the corresponding schedule(s) accordingly to ensure that the LRAMVA balance
8 is consistent between the three references.
- 9 c) If Hydro Ottawa were to successfully dispose of the 2021-2023 LRAMVA balance requested in
10 this application, please confirm if the LRAMVA balance would be zero and if Hydro Ottawa
11 intends to close out the LRAMVA account. If not, please explain why Hydro Ottawa intends to
12 keep the LRAMVA account open, and if Hydro Ottawa plans on filing a LRAMVA claim for
13 disposition in a future proceeding (and if so, when and for which years).
- 14 d) Please discuss why Hydro Ottawa has not calculated LRAMVA for historic CDM programs up
15 until the end of 2025 to allow for full consideration of all related amounts until its next rate
16 period. As part of the response, please consider the OEB's NWS Guidelines (reference 5),
17 which indicates on page 30 that distributors are not to use an LRAMVA for CDM activities
18 funded by the IESO through the 2021-2024 CDM Framework (with the possible exception of the
19 Local Initiative Program).

20

21 **RESPONSE(S):**

22

- 23 a) As detailed in Schedule 9-1-5 - LRAM Variance Account, Hydro Ottawa is proposing the
24 disposition of LRAMVA balances up to December 31, 2023, with carrying charges to December
25 31, 2025. For the LRAMVA balance proposed to be disposed of in this rate application, please
26 refer to interrogatory response 1-Staff-1 for the updated balance.
- 27
- 28 b) Please refer to interrogatory response 1-Staff-1.

1 c) If Hydro Ottawa were to successfully dispose of the 2021-2023 LRAMVA balance requested in
2 this application, the LRAMVA balance related to 2021-2023 would be cleared. However,
3 amounts related to 2024 and 2025 would still need to be recorded and disposed of. This is the
4 reason Table 4 - Proposed Action on Group 2 Accounts for 2025 (Exhibit 9 Tab 1 Schedule 1
5 page 6), the LRAM Variance account is indicated to continue. As such, Hydro Ottawa will
6 continue to utilize the LRAMVA to track and measure the financial impact of various CDM
7 initiatives to the end of 2025 per Hydro Ottawa's 2021-2025 Approved Settlement Agreement¹.
8 Hydro Ottawa plans on filing a LRAMVA claim for disposition in a future proceeding once the
9 IESO releases reports for 2024 and 2025.

10
11 d) Hydro Ottawa has not calculated LRAMVA for 2024 and 2025 as the IESO has not released its
12 reports for 2024 and 2025. LRAMVA savings for those years will be calculated once these
13 reports are released, which will allow for full consideration of all related amounts until its next
14 rate period. The OEB's Non-wires Solutions Guidelines for Electricity Distributors
15 (EB-2024-0118), previously named Conservation and Demand Management (CDM) Guidelines,
16 was released December 2021, after the proposed settlement agreement was approved. The
17 timing of the updated Guidance made it unclear how distributors were to consider future
18 conservation programs within Revenue Load Forecasts and LRAM structure. As part of Hydro
19 Ottawa 2021-2025 proposed Load Forecast it had forecasted embedded future saving based on
20 historical CDM success in its services territory against future IESO targets. The updated
21 guidelines aligned with this approach, however it had already been agreed as part of the
22 Settlement that future CDM would be considered and reviewed as part of an LRAM variance
23 account. This includes balances to the end of 2025.

24
25 As noted as part of this interrogatory, although the LRAMVA is no longer a default, it is not
26 disallowed. For 2026-2030, Hydro Ottawa has proposed embedding estimated eDSM as part of
27 its revenue forecast and is not proposing to maintain the LRAMVA Account effective January 1,
28 2026 (for load consumed after January 1, 2026).

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

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-219**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: HOL_Attachment 9-1-5(A) - OEB LRAMVA Workform_20250415.xlsx

8 Ref. 2: HOL_Attachment 9-1-5(B) – IESO Final Verified 2017 CDM Summary
9 Report_20250415.xlsx

10 Ref 3: Exhibit 9 / Tab 1 / Schedule 5 / pp. 1-9 (pdf pp. 66-74)

11
12 **Preamble:**

13 From the OEB LRAMVA Workform, it is unclear how the 1) net energy savings persistence, and 2)
14 net peak demand savings persistence, reported under tabs “5. 2015-2027 LRAM” and “7.
15 Persistence Report” were determined/calculated as the values are hardcoded. It is also unclear if
16 and how the values in IESO’s Final Verified 2017 CDM Summary Report were used in the
17 compilation of the OEB LRAMVA Workform to arrive at the LRAMVA balance requested for
18 disposition.

19
20 **QUESTION(S):**

21
22 a) Please clarify and provide the supporting calculations for the values reported under Tabs 5 and
23 Tab 7 of the OEB LRAMVA Workform.

24
25
26 **RESPONSE(S):**

27
28 a) Please refer to Attachment 9-Staff-219(A) - HOL CDM&eDSM savings showing the net energy
29 savings persistence and net peak demand savings persistence used in Tab 5. 2015-2027 LRAM
30 of the LRAMVA workform.

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-220**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 3 / Schedule 1 / pp. 31-32 (pdf pp. 41-42)

8 Ref. 2: OEB Letter Re: Revisions to the Ontario Energy Board Cost Assessment Model, February 9,
9 2016

10
11 **Preamble:**

12 In reference 1, Hydro Ottawa states that in 2020 it incurred OEB assessed costs of \$486,978.09
13 that have been recorded into Account 1508 Other Regulatory Assets - Sub-Account - OEB Cost
14 Assessment Variance.

15
16 Reference 2 states that the OEB established Account 1508 Other Regulatory Assets, Sub-account
17 OEB Cost Assessment Variance to record any material differences between OEB cost assessments
18 built into rates, and cost assessments that would result from the application of the new cost
19 assessment model effective April 1, 2016.

20
21 **QUESTION(S):**

22
23 a) Please clarify whether \$486,978 represents the OEB cost assessment incurred by Hydro
24 Ottawa in 2020 or a variance between the OEB cost assessments that were built into rates and
25 cost assessments that would result from the application of the new cost assessment model
26 effective April 1, 2026.

27 b) Please provide supporting calculations used to derive \$486,978

1

2 **RESPONSE(S):**

3

4 a) The amount of \$486,978 represents a variance between OEB cost assessments that were built
5 into rates at the time of the issuance of the OEB's revisions, and cost assessments that would
6 result from the application of the new Cost Assessment Model effective April 1, 2016¹.

7

8 b) The \$486,978 variance represents the difference between total quarterly invoices of \$1,403,298,
9 the 2016-2020 Rate Application's annual OEB Assessment budget of \$916,311. Table A below
10 details this calculation.

11

12

Table A - Quarterly OEB Invoices vs. Approved Budget 2016-2020

Period	Invoice #	Invoice amount	Amount in Rates	Differential
Jan 1 to Mar 31	19204040	\$ 355,357	\$ 229,078	\$ 126,279
Apr 1 to Jun 30	20211040	\$ 352,014	\$ 229,078	\$ 122,936
Jul 1 to Sep 30	20212040	\$ 347,963	\$ 229,077	\$ 118,886
Oct 1 to Dec 31	20213040	\$ 347,964	\$ 229,079	\$ 118,885
Total		\$ 1,403,298	\$ 916,311	\$ 486,987

13

¹ Ontario Energy Board, Letter re: *Revisions to the Ontario Energy Board Cost Assessment Model* (February 9, 2016).

1 **INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF**

2
3 **9-Staff-221**

4
5 **EVIDENCE REFERENCE:**

6
7 Ref. 1: Exhibit 9 / Tab 3 / Schedule 1 / p. 3 (pdf p. 86)

8 Ref. 2: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

9
10 **QUESTION(S):**

11
12 a) Please provide the support for the credit balance of \$208,445 requested for disposition for
13 Sub-Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential
14 Carrying Charges, as reported in Table 1 of Reference 1.

15
16
17 **RESPONSE(S):**

18
19 a) Please refer to Attachment 9-Staff-221(B) - 2023 & Projected Interest for the support of credit
20 balance of \$208,445 requested for disposition for Sub-Account 1522, Pension & OPEB Forecast
21 Accrual versus Actual Cash Payment Differential Carrying Charges, as reported in Table 1 of
22 Reference 1.

23
24 Please refer to Attachment 1-Staff-1(C) - OEB_Workform - 2026 DVA_Continuity_Schedule for
25 an updated Deferral and Variance Account Continuity Schedule with the inclusion of 2024
26 balances. There is a credit balance of \$229,512 requested for disposition for Sub-Account 1522,
27 Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.
28 Please refer Attachment 9-Staff-221(A) - 2024 & Projected Interest for the support of credit
29 balance of \$229,512.