INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-1

EVIDENCE REFERENCE:

QUESTION(S):

Updated Revenue Requirement Work Form (RRWF) and Models
Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed as part of the initial application. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist with understanding the changes.

In addition, please file an updated set of models that reflects the interrogatory responses and 2024 Actual amounts. Please ensure the models used are the latest available models on the OEB's 2026 Electricity Distribution Rate Applications webpage.

RESPONSE(S):

1. INTRODUCTION

Please see the following Appendices and Workforms that have been updated for 2024 Actuals and impact of the change to the ADMS program as noted in the correspondence filed on July 7, 2025 and noted in Section 4.1 below.

Please also note, as identified in response to interrogatory 2-SEC-36, Hydro Ottawa acknowledged a discrepancy between the energization date and the requested budget timelines for the Cyrville transformer capacity upgrade project in the original application material. Given the timing of discovering this error, Hydro Ottawa has not adjusted the Revenue Requirement and bill impacts for this error and will do so at a later stage in the application.

Chapter 2 Appendices[1]:

- Attachment 1-Staff-1(A) - Chapter 2 Appendices

The following Chapter 2 Appendices have been updated and included in Attachment 1-Staff-1(A):

- Appendix 2-AA - Capital Programs Table
- Appendix 2-AB - Capital Expenditure Summary
- Appendix 2-BA - 2021-2025 Fixed Asset Continuity Schedule
- Appendix 2-BA - 2026-2030 Fixed Asset Continuity Schedule
- Appendix 2-C - 2021-2025 Depreciation and Amortization Expense
- Appendix 2-C - 2026-2030 Depreciation and Amortization Expense
- Appendix 2-D - Overhead Expense
- Appendix 2-G - Service Quality and Reliability Indicators
- Appendix 2-H - Other Revenue
- Appendix 2-IB - Load Forecast Analysis
- Appendix 2-JA - Summary of Recoverable OM&A Expenses
- Appendix 2-JC - OM&A Programs Table
- Appendix 2-K - Employee Costs
- Appendix 2-N - Shared Services and Corporate Cost Allocation
- Appendix 2-R - Loss Factors
- Appendix 2-OA - Capital Structure
- Appendix 2-OB - Debt Instruments

[1] Includes adjustments for any errors noted in Appendix- A - Table of Revisions of Hydro Ottawa's IRR Cover Letter

OEB Workforms[2]:

- Attachment 1-Staff-1 (B) OEB Workform - 2026 Commodity Accounts Analysis
- Attachment 1-Staff-1 (C) OEB Workform - 2026 Deferral and Variance Accounts (Continuity Schedule
- Attachment 1-Staff-1 (D) 2026 RTSR Workform EV
- Attachment 1-Staff-1 (E) - 2026-2030 Income Tax PILS Workform
- Attachment 1-Staff-1 (F) - OEB Workform - 2025 Current and 2026 Proposed Tariff of Rates and Charges
- Attachment 1-Staff-1 (G) - 2026-2030 Bill Impacts Model
- Attachment 1-Staff-1 (H) - 2026 Cost Allocation Model
- Attachment 1-Staff-1 (I) - 2027 Cost Allocation Model
- Attachment 1-Staff-1 (J) - 2028 Cost Allocation Model
- Attachment 1-Staff-1 (K) - 2029 Cost Allocation Model
- Attachment 1-Staff-1 (L) - 2030 Cost Allocation Model
- Attachment 1-Staff-1 (M) - OEB Workform - 2026 Revenue Requirement Workform
- Attachment 1-Staff-1 (N) - OEB Workform - 2027 Revenue Requirement Workform
- Attachment 1-Staff-1 (O) - OEB Workform - 2028 Revenue Requirement Workform
- Attachment 1-Staff-1 (P) - OEB Workform - 2029 Revenue Requirement Workform
- Attachment 1-Staff-1 (Q) - OEB Workform - 2030 Revenue Requirement Workform
- Attachment 1-Staff-1 (R) - OEB LRAMVA Workform

2. REVENUE REQUIREMENT

Hydro Ottawa's Service Revenue Requirement has been updated to $308.1M for the 2026 Test Year. The change and drivers are listed in Table A and explained in detail below.

[2] Ibid.

Table A - Revenue Requirement

	OEB-Approved	Test Year (Original)	Test Year (Updated)	Change		Drivers
	2025	2026	2026	$	%	
Return on Rate Base	$ 79,365	$ 91,549	$ 90,858	$ 691	1%	Opening rate base has been updated to reflect 2024 actual as well as a shift of the ADMS from 2025 to 2026 and 2027.
Distribution Expenses (not including amortization)	$ 104,927	$ 140,010	$ 140,010	-	-	
Amortization	$ 62,125	$ 67,205	$ 66,101	$ 1,104	2%	Less amortization due to the change noted above.
Payment in Lieu of Taxes	$ 7,283	$ 6,638	$ 6,153	$ 485	7%	Due to the change noted above.
Other Expenses - PILS	$ (3,658)	$ 4,590	$ 5,066	$ (476)	(10)%	Updated to reflect the latest PILs calculation.
Service Revenue Requirement	**$ 250,042**	**$ 309,992**	**$ 308,188**	**$ 1,804**	**1%**	

2.1. REVENUE DEFICIENCY/SUFFICIENCY 2026-2030

Table B below shows the updated 2026-2030 base revenue calculation.

Table B – Revenue Deficiency/Sufficiency for 2026-2030 ($'000s)[3]

	Test Years				
	2026	**2027**	**2028**	**2029**	**2030**
Return on Rate Base	$ 90,858	$ 101,462	$ 114,071	$ 123,526	$ 130,343
Distribution Expenses (not including amortization)	$ 140,010	$ 147,263	$ 154,891	$ 162,914	$ 171,353
Depreciation, amortization	$ 66,101	$ 74,529	$ 82,242	$ 88,350	$ 94,316
Payment in Lieu of Taxes (PILS)	$ 6,153	$ 3,846	$ 11,567	$ 12,415	$ 15,334
Other Expenses - PILS Contribution	$ 5,066	$ 4,096	-	-	-
Service Revenue Requirement	**$ 308,188**	**$ 331,196**	**$ 362,772**	**$ 387,206**	**$ 411,346**
Less Revenue Offsets	$ 11,018	$ 10,697	$ 10,859	$ 11,123	$ 11,460
Revenue Requirement from Rates	**$ 297,170**	**$ 320,499**	**$ 351,913**	**$ 376,083**	**$ 399,887**
Forecasted Load at Prior Year Rates	$ 249,050	$ 299,129	$ 323,650	$ 355,356	$ 379,173
Yearly Revenue Deficiency	**$ (48,121)**	**$ (21,369)**	**$ (28,263)**	**$ (20,727)**	**$ (20,714)**
Cumulative Revenue Deficiency	**$ (48,121)**	**$ (69,490)**	**$ (97,753)**	**$ (118,480)**	**$ (139,194)**

2.2. PAYMENT IN LIEU OF TAXES ("PILS")

Hydro Ottawa is providing an update to PILS for the impacts of the 2024 actual capital additions, the shift in the ADMS project capital spending as noted in Section 4.1 below, and the filing of Hydro Ottawa's 2024 Tax Return. A summary of the updated PILS amounts can be found in Table C below. An updated Modified PILS Tax Model/PILS Workform (PILS Model) can be found as Attachment 1-Staff-1(E) - 2026-2030 Income Tax PILS Workform. Hydro Ottawa's 2024 corporate tax return can be found as Attachment 6-Staff-184(A) - 2024 Tax Return - REDACTED.

[3] Totals may not sum due to rounding. The Other Expenses - PILs contribution amounts are preliminary and will be updated upon finalization of Revenue Requirement for 2026 and 2027.

Table C - Updated PILS for 2024 Actual and Revised Grossed Up PILS for 2025 Bridge Year and 2026-2030 Test Years ($'000s)

Year	Income Taxes/PILS Grossed Up
2024 Actual (as per corporate tax return)	$1,004
2025	$ 9,596
2026	$ 6,153
2027	$3,846
2028	$11,567
2029	$ 12,415
2030	$ 15,334

Additionally, Hydro Ottawa is providing updated tables to reconcile Additions and Depreciation as per Updated Appendix 2-BA and Additions and Depreciation for tax purposes. These reconciliation tables were originally introduced as evidence as part of the Error Checking responses submitted by Hydro Ottawa on June 4, 2025 as requested by the OEB. Refer to the following updated Tables D, F and G, and an additional Table E below, which has been included to agree to updated Appendix 2-BA, Attachment 1-Staff-1(E) - 2026-2030 Income Tax PILS Workform and Hydro Ottawa's 2024 tax return.

Table D - Reconciliation of Fixed Asset Continuity Schedule Additions and Capital Additions in PILS Workforms for 2025-2030

	2025	2026	2027	2028	2029	2030
Fixed Asset Total Additions (as per Appendix 2-BA)	$115,245,851	$206,565,080	$288,267,059	$289,317,777	$196,570,122	$212,931,238
Add : PILS Contribution Adjustment[4]	-	$5,066,000	$4,096,000	-	-	-
Add : Capital SR&ED Tax Credits[5]	$1,336,864	$576,000	$839,000	$860,000	$695,000	$497,000
Less : SR&ED expenses capitalized[6]	($6,495,043)	($3,953,284)	($5,717,224)	($5,858,285)	($4,752,484)	($3,429,917)
Less : Land[7]	($2,615,522)	-	($205,840)	($5,739,473)	($607,613)	($1,216,803)
Add : Misc adjustment	$2,419	-	-	-	-	-
PILS Workforms Schedule 8 Additions	**$107,474,569**	**$208,253,796**	**$287,278,995**	**$278,580,019**	**$191,905,025**	**$208,781,518**

Table E - Reconciliation of Fixed Asset Continuity Schedule Additions to Tax Return for 2023 & 2024 Actuals

Reconciliation of Fixed Asset Additions (Appendix 2-BA) to Tax Returns for 2023 & 2024 Actuals	2023	2024
Fixed Asset Total Additions (as per Appendix 2-BA)	$92,514,346	$114,001,711
Add : non distribution assets additions	$477,204	$43,538
Add : Capital SR&ED Tax Credits[5]	$434,441	$741,136
Less : SR&ED expenses capitalized[6]	($4,643,539)	($4,540,826)
Less : Land[7]	-	($8,473,340)
Less : AFUDC	($694,333)	($964,805)
Additions for Tax Return (as per Schedule 8)	**$ 88,088,119**	**$ 100,807,414**

[4] This represents the PILS contribution adjustment which is explained in Schedule 9-1-4, section 7 and please see Table 4 in that section. This amount is preliminary and will be updated for changes in capital assets additions for 2026 and 2027.
[5] SR&ED Tax Credits are recorded as credits, included in OEB Account 2440 for accounting purposes, and depreciated over ten years. Please see Table 4 in Schedule 6-2-1.
[6] This represents current year SR&ED expenditures capitalized for accounting purposes but expensed for tax purposes. SR&ED expenditures are considered current expenditures for tax purposes.
[7] Land is not depreciable for tax purposes and not included in Schedule 8.

Table F - Reconciliation of Fixed Asset Continuity Schedule Depreciation and PILS Workforms Amortization for 2023-2030

	2023	2024	2025	2026	2027	2028	2029	2030
Fixed Asset Depreciation (as per Appendix 2-BA)	$55,661,147	$58,327,955	$61,744,880	$66,100,856	$74,529,071	$82,242,258	$88,350,229	$94,316,077
Add : Capital SR&ED Tax Credits Amortization[8]	$229,861	$395,589	$370,818	$446,104	$438,891	$436,151	$483,300	$542,901
Add : PILS Contribution Adjustment Amortization[9]	-	-	-	$70,361	$197,611	$254,500	$254,500	$254,500
Add: Non Rate-Regulated Utility Assets Amortization[10]	$408,418	$409,537	-	-	-	-	-	-
Add: Non-rate Base Assets Amortization/Transfer[11]	$62,159	$59,980	-	-	-	-	-	-
PILS Workforms Amortization[12]	**$56,361,585**	**$59,193,061**	**$62,115,698**	**$66,617,322**	**$75,165,572**	**$82,932,909**	**$89,088,029**	**$95,113,478**

Table G - Reconciliation PILS Amortization from Updated Table F to 2023 & 2024 Tax Returns & Tabs H1 & A1

Reconciliation PILS Amortization from Table 8 to 2023 & 2024 Tax Returns & Tabs H1 & A1	2023	2024
Amortization of tangible assets (as per tax returns & Tab H1 & A1)	$55,441,000	$58,852,000
Amortization of intangible assets (as per tax returns & Tab H1 & A1)	$8,646,000	$9,348,000
Deferred revenue amortization (as per tax returns & Tab H1 & A1	$(7,725,415)	$(9,006,939)
Amortization as per Updated Table F reconciliation	**$ 56,361,585**	**$59,193,061**

[8] This represents the amortization of SR&ED tax credits over ten years, see footnote #5 in this Schedule.
[9] This represents the amortization of the PILS contribution adjustment, which is explained in Schedule 9-1-4 section 7 and see also footnote #4 above.
[10] This represents the amortization on non rate regulated utility assets which are included for tax return purposes.
[11] This represents the amortization and transfer on non-rate base assets which are included for tax return purposes.
[12] See Updated Table G below for a breakdown of the Reconciliation of PILS Amortization to 2023 & 2024 Tax Returns & Tabs H1 & A1.

The modified PILS model, Attachment 1-Staff-1(E) - 2026-2030 Income Tax PILS Workform, has been updated to reflect Hydro Ottawa's 2024 corporate tax return which was filed in June 2025 and to relabel the 2024 Year as a Historical Year instead of as a Bridge Year.

Updates and relabelling have been made to the following Tabs:

- Tab "Table of Contents" changes:
  - from "Bridge Year 2024" to "Historical Year 2024"
  - from "A0 PILs,Tax Provision Bridge 24" to "A0 PILs,Tax Provision Hist 24"
  - From "A1 Taxable Income Bridge 24" to "A1 Taxable Income Hist 24"
  - From "A4 Sch 4 Loss Bridge 24" to "A4 Sch 4 Loss Hist 24"
  - From "A8 Sch 8 CCA Bridge 24" to "A8 Sch 8 CCA Hist 24"
  - From "A13 Sch 13 Reserves Bridge 24" to "A13 Sch 13 Reserves Hist 24"
- Tab "A. Data Input Sheet 26-30" changes:
  - Change from "Bridge Year 2024" to "Historical Year 2024"
  - Historical year has been expanded to include both 2023 and 2024 (see columns G & H)
  - The dividend for 2024 and 2025 in cells H38 and I38 was changed to "Yes."
  - The capital gain or losses for 2024 in cell H30 was changed to "Yes."
  - The years were added to cells G25 through J25.
- Tab A0: tab name changed From "A0 PILs,Tax Provision Bridge 24" to "A0 PILs,Tax Provision Hist 24" and updated to reflect 2024 tax return
- Tab A1: tab name changed From "A1 Taxable Income Bridge 24" to "A1 Taxable Income Hist 24" and updated to reflect 2024 tax return
- Tab A4: tab name changed from "A4 Sch 4 Loss Bridge 24" to "A4 Sch 4 Loss Hist 24" and updated to reflect 2024 tax return
- Tab A8: tab name changed from "A8 Sch 8 CCA Bridge 24" to "A8 Sch 8 CCA Hist 24" and updated to reflect 2024 tax return
- Tab A13: tab name changed from "A13 Sch 13 Reserves Bridge 24" to "A13 Sch 13 Reserves Hist 24" and updated to reflect 2024 tax return

These updates to Attachment 1-Staff-1(E) - 2026-2030 Income Tax PILS Workform (PILS Model) were made in order to have these tabs agree to Hydro Ottawa's 2024 corporate tax return. The tax updates to the 2024 Historical for 2024 actual additions and 2024 tax return flow to the 2025 Bridge Year and 2026 to 2030 Test Years. For example, the December 31, 2024 ending UCC balance of Schedule 8 in the PILS Model (updated to agree to the 2024 tax return) changes the January 1, 2025 opening UCC balance which changes the 2025 CCA deduction with subsequent corresponding changes of UCC and CCA to the 2026 - 2030 Test Years.

2.3. OTHER REVENUE

Table H below presents the Other Revenue Summary for 2023-2025, incorporating 2024 Historical and the variance to the 2024 Bridge year. The original presentation of this data can be found in Table 2 of Schedule 6-3-1 - Other Revenue Summary.

Table H - Historical and Bridge Years Other Revenue Summary 2023-2025 ($'000s)[13]

Other Revenue	2023	2024			2025
	Historical	Bridge	Historical	Variance	Bridge
Specific Service Charges (4235)	$ 1,806	$ 2,170	$ 1,995	$ (174)	$ 2,231
Late Payment Charges (4225)	$ 1,605	$ 1,650	$ 1,848	$ 198	$ 1,700
Other Operating Revenue (4082, 4084, 4086, 4090, 4210)	$ 6,059	$ 6,209	$ 6,280	$ 70	$ 6,435
Other Income & Deductions (4325, 4330, 4362, 4375, 4380, 4405)	$ (965)	$ (1,252)	$ (3,874)	$ (2,622)	$ (1,681)
TOTAL OTHER REVENUE	**$ 8,504**	**$ 8,777**	**$ 6,249**	**$ (2,528)**	**$ 8,686**

The total other revenue variance decreased $2.5M from 2024 Bridge to 2024 Actuals. The primary contributor of the variance was Services to Third Parties (net of costs) included in Other Income & Deductions. The loss in 2024 was greater than anticipated due to the external services employed to clear backlogs stemming from the 2023 labour disruption.

[13] Totals may not sum due to rounding.

3. REVENUE LOAD FORECAST SUMMARY

The revenue load forecast remains unchanged, no update is required due to responses to interrogatories. Appendix 2-IB has been updated to include 2024 Historical Actual and weather normalized kWh and kW as well as Historical monthly average customer and connection counts.

4. RATE BASE

4.1. CAPITAL

As part of Hydro Ottawa's Original Evidence it was indicated that the Advanced Distribution Management System (ADMS) was undergoing a comprehensive review and that updated information would be filed no later than with responses to interrogatories.

In early 2025, Hydro Ottawa paused its ADMS program (including SCADA Upgrades) and completed a comprehensive review. This review was vital for Hydro Ottawa to navigate the ongoing energy transition, address dynamic changes within the energy sector, and optimize operational capabilities.

The review prompted modifications in the functionality sequence to reflect current priorities and technological advancements, focusing on essential capabilities for the 2026 to 2030 period. As a direct result, some capital expenditures and additions have been shifted into the 2026 to 2030 rate period. The overall capital expenditures and additions for grid modernization over the 2024 to 2030 period are not forecasted to change. Table I below outlines the capital expenditures as per the result of the shift in schedule. Please refer to the response to interrogatory 2-Staff-33 for additional information.

Table I - Grid Technology Historical, Bridge and Test Year Expenditures ($'000 000s)

Budget Program	Historical Years				Bridge Year	Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SCADA Upgrades	$ 0.2	$ 2.6	$ 5.6	$ 5.1	$ 3.3	$ 3.4	$ 0.6	-	-	-
ADMS Upgrades & Enhancements	-	-	-	-	-	-	$ 1.0	$ 0.1	$ 5.0	$ 0.3
TOTAL	**$ 0.2**	**$ 2.6**	**$ 5.6**	**$ 5.1**	**$ 3.3**	**$3.4**	**$ 1.6**	**$ 0.1**	**$ 5.0**	**$ 0.3**
5-YEAR TOTAL					**$ 16.8**					**$ 10.4**

The related impact to capital additions reduced the total 2021-2025 OEB-Approved versus Historical and Bridge Year net in-service capital additions variance from $44.9M[14] to $30.4M as seen in Table J below. In addition this update resulted in an increase in the capital additions of $14.5M in 2026-2030 as noted in Table K below. Hydro Ottawa is not proposing to adjust capital expenditures or additions as a result of the 2024 Actuals.

Updated ADMS - Table J - Variances in 2021-2025 Net In-Service Capital Additions - OEB-Approved vs. Historical and Bridge Year Amounts ($'000s)

Investment Category	2021-2025 Approved	2021-2025 Actual/Bridge	Var. ($)	Var (%)
System Access	$ 86,018	$ 114,733	$ 28,715	33%
System Renewal	$ 211,821	$ 239,167	$ 27,346	13%
System Service	$ 142,375	$ 129,738	$ (12,637)	(9)%
General Plant	$ 114,837	$ 101,822	$ (13,015)	(11)%
Net In-Service Additions	**$ 555,052**	**$ 585,459**	**$ 30,408**	**5%**

[14] Schedule 2-1-1 Rate Base Overview Section 3.0 Table 4

Updated ADMS Table K – Historical, Bridge and Test Years Additions by Investment Category ($'000s)

Investment Category	2026-2030 Test Years		Var. ($)	Var (%)
	Original	Revised		
System Access	$ 189,789	$ 189,789	-	0%
System Renewal	$ 432,341	$ 432,341	-	0%
System Service	$ 437,562	$ 452,066	$ 14,504	3%
General Plant	$ 119,455	$ 119,455	-	0%
NET CAPITAL ADDITIONS	**$ 1,179,147**	**$ 1,193,651**	**$ 14,504**	**3%**

As a result of the change to the ADMS project, System Service capital expenditures are increased in 2026 and 2027 by $3.4M and $0.6M, respectively. See Table L for the updated capital expenditures for 2026-2030 as a result of the ADMS project change.

Table L – Capital Expenditure Test Years Summary ($'000s) updated for the ADMS program

Investment Category	Test Years					Average
	2026	2027	2028	2029	2030	2026-2030
System Access	$ 86,169	$ 78,690	$ 66,190	$ 66,978	$ 71,472	$ 73,900
System Renewal	$ 85,348	$ 83,396	$ 80,714	$ 86,903	$ 95,343	$ 86,341
System Service	$ 102,715	$ 125,945	$ 76,050	$ 85,922	$ 86,912	$ 95,509
General Plant	$ 38,325	$ 23,583	$ 33,025	$ 27,872	$ 11,026	$ 26,766
GROSS CAPITAL EXPENDITURES	**$ 312,557**	**$ 311,614**	**$ 255,979**	**$ 267,675**	**$ 264,752**	**$ 282,515**
Capital Contributions	$ (50,947)	$ (50,591)	$ (38,447)	$ (32,197)	$ (41,052)	$ (42,647)
NET CAPITAL EXPENDITURES	**$ 261,610**	**$ 261,023**	**$ 217,532**	**$ 235,478**	**$ 223,700**	**$ 239,869**

Table M below summarizes the revised capital expenditures for the 2021 - 2025 Historical/Bridge period and the 2026-2030 Test Years as a result of the $4.1M shift of ADMS capital expenditures from 2024 and 2025 to 2026 and 2027. The related impact to capital expenditures reduced the total 2021-2025 OEB-Approved versus Historical and Bridge Year net capital expenditures variance from $102.8M to $98.8M.

Updated ADMS Table M – Historical, Bridge and Test Years Expenditures by Investment Category ($'000s)

Investment Category	2021 - 2025 Historical/Bridge		2026-2030 Test Years	
	Original	Revised	Original	Revised
System Access	$ 292,570	$ 292,570	$ 369,500	$ 369,500
System Renewal	$ 232,333	$ 232,333	$ 431,704	$ 431,704
System Service	$ 161,104	$ 157,032	$ 473,472	$ 477,544
General Plant	$ 76,405	$ 76,405	$ 133,830	$ 133,830
GROSS CAPITAL EXPENDITURES	**$ 762,412**	**$ 758,340**	**$ 1,408,505**	**$ 1,412,577**
Capital Contributions	$ (162,024)	$ (162,024)	$ (213,234)	$ (213,234)
TOTAL NET CAPITAL EXPENDITURES	**$ 600,388**	**$ 596,316**	**$ 1,195,271**	**$ 1,199,343**

In addition, as mentioned in the introduction and as identified in response to interrogatory 2-SEC-36, Hydro Ottawa acknowledged a discrepancy between the energization date and the requested budget timelines for the Cyrville transformer capacity upgrade project in the original application material. Given the timing of discovering this error, Hydro Ottawa has not adjusted the Revenue Requirement and bill impacts for this error and will do so at a later stage in the application.

4.2. COST OF CAPITAL

Cost of Capital has been updated as a result of the changes to rate base shown in Table O. Please refer to updated Appendices 2-OA and 2-OB in Excel Attachment 1-Staff-1(A) - Chapter 2 Appendices. As reflected in the updated Appendix 2-OB, a $72.6 million promissory note was issued by Hydro Ottawa to Hydro Ottawa Capital Corporation on July 2, 2025, although the proposed long-term debt rate, as described in Schedule 5-1-1 - Cost of Capital and Capital Structure, remains unchanged.

4.3. WORKING CAPITAL

Detailed in Section 8 below, Hydro Ottawa is proposing to update the total loss factors. The impact of the updated loss factor on working capital allowance on average is $17k or 0.03% per test year. This is an insignificant change, as such the cost of power estimate amount in working capital allowance has not been updated.

4.4. RATE BASE

Due to changes in net in-service capital additions identified in Tables J and K, rate base for 2024-2030 has been updated. Table N provides an updated rate base for 2021-2025. The original presentation of this data can be found in Table 1 of Schedule 2-1-1 - Rate Base Overview.

Table N – Summary of Historical and Bridge Year Rate Base 2021-2025 ($'000s)

	Historical Years				Bridge Years
	2021	2022	2023	2024	2025
Opening Gross Assets	$ 1,345,265	$ 1,469,459	$ 1,607,631	$ 1,692,408	$ 1,802,863
Closing Gross Assets	$ 1,469,459	$ 1,607,631	$ 1,692,408	$ 1,802,863	$ 1,915,749
Average Gross Assets	**$ 1,407,362**	**$ 1,538,545**	**$ 1,650,020**	**$ 1,747,636**	**$ 1,859,306**
Opening Accumulated Depreciation	$ (271,071)	$ (320,785)	$ (372,547)	$ (426,954)	$ (483,214)
Closing Accumulated Depreciation	$ (320,785)	$ (372,547)	$ (426,954)	$ (483,214)	$ (543,838)
Average Accumulated Depreciation	**$ (295,928)**	**$ (346,666)**	**$ (399,750)**	**$ (455,084)**	**$ (513,526)**
Opening Net Book Value	$ 1,074,194	$ 1,148,673	$ 1,235,084	$ 1,265,455	$ 1,319,649
Closing Net Book Value	$ 1,148,673	$ 1,235,084	$ 1,265,455	$ 1,319,649	$ 1,371,911
Average Net Book Value	**$ 1,111,434**	**$ 1,191,879**	**$ 1,250,269**	**$ 1,292,552**	**$ 1,345,780**
Working Capital Allowance	$ 70,733	$ 71,503	$ 71,908	$ 73,992	$ 75,249
RATE BASE - revised	**$ 1,182,167**	**$ 1,263,381**	**$ 1,322,177**	**$ 1,366,544**	**$ 1,421,029**
RATE BASE - original	**$ 1,182,167**	**$ 1,263,381**	**$ 1,322,177**	**$ 1,369,386**	**$ 1,430,910**
Variance	**-**	**-**	**-**	**$ (2,842)**	**$ (9,881)**

Table O below details the proposed increase in rate base for 2026-2030 Test years due to the ADMS project. The original presentation of this data can be found in Table 17 of Schedule 2-1-1 - Rate Base Overview.

Table O – Summary of 2026-2030 Rate Base ($'000s)

	Test Years				
	2026	2027	2028	2029	2030
Opening Gross Assets	$ 1,915,749	$ 2,118,569	$ 2,400,711	$ 2,683,428	$ 2,872,446
Closing Gross Assets	$ 2,118,569	$ 2,400,711	$ 2,683,428	$ 2,872,446	$ 3,076,873
Average Gross Assets	**$ 2,017,159**	**$ 2,259,640**	**$ 2,542,070**	**$ 2,777,937**	**$ 2,974,659**
Opening Accumulated Depreciation	$ (543,838)	$ (607,772)	$ (678,224)	$ (755,874)	$ (838,692)
Closing Accumulated Depreciation	$ (607,772)	$ (678,224)	$ (755,874)	$ (838,692)	$ (926,492)
Average Accumulated Depreciation	**$ (575,805)**	**$ (642,998)**	**$ (717,049)**	**$ (797,283)**	**$ (882,592)**
Opening Net Book Value	$ 1,371,911	$ 1,510,796	$ 1,722,487	$ 1,927,554	$ 2,033,754
Closing Net Book Value	$ 1,510,796	$ 1,722,487	$ 1,927,554	$ 2,033,754	$ 2,150,381
Average Net Fixed Assets	**$ 1,441,354**	**$ 1,616,642**	**$ 1,825,021**	**$ 1,980,654**	**$ 2,092,067**
Working Capital Allowance	$ 79,540	$ 81,751	$ 84,442	$ 87,076	$ 89,773
RATE BASE - revised	**$ 1,520,894**	**$ 1,698,393**	**$ 1,909,463**	**$ 2,067,730**	**$ 2,181,841**
RATE BASE - original	**$ 1,532,457**	**$ 1,701,720**	**$ 1,907,062**	**$ 2,065,315**	**$ 2,179,372**
Variance	**$ (11,563)**	**$ (3,327)**	**$ 2,401**	**$ 2,415**	**$ 2,469**

5. OPERATIONS, MAINTENANCE, AND ADMINISTRATION EXPENSE SUMMARY

Table P below is provided as a 2024 update to Table 1 in Exhibit 4-1-1 - Operations, Maintenance and Administration Summary. Hydro Ottawa is not proposing any change in OM&A test years related to the 2024 Update. Additional details are noted in Appendix 2-JA - Summary of Recoverable OM&A Expenses and Appendix 2-JC - OM&A Programs Table of Attachment 1-Staff-1(A) - Chapter 2 Appendices.

Appendix 2-N - Shared Services and Corporate Cost Allocation in Attachment 1-Staff-1(A) has corrected the percentage of corporate costs allocated from the Legal and Board of Directors services in the 2024 Bridge year. The dollar amount allocated is unchanged as the correction only applied to the percentages.

Table P – OM&A Variances ($'000s)

	Year	OM&A ($)	Variance ($)	Variance (%)
OEB Approved	2021	$ 90,600		
Historical Years	2021	$ 84,737	$ (5,863)	(6.47%)
	2022	$ 100,536	$ 15,798	18.64%
	2023	$ 112,778	$ 12,242	12.18%
	2024	$ 115,090	$ 2,312	2.05%
Bridge Year	2025	$ 118,922	$ 3,832	3.33%
Test Years	2026	$ 140,010	$ 21,088	17.73%
	2027	$ 147,263	$ 7,253	5.18%
	2028	$ 154,891	$ 7,628	5.18%
	2029	$ 162,914	$ 8,023	5.18%
	2030	$ 171,353	$ 8,439	5.18%

Overall, 2024 Actual OM&A was materially on budget at $115.1M compared to the 2024 Bridge of $115.3M. The underspend variance of $0.2M represents a 0.2% variance. While the combined variances of all OM&A programs is not material, the following program level variances are provided:

- **Distribution Support Costs** were $2.6M less than the 2024 Bridge. The underspend was driven by lower compensation costs coupled with higher than expected labour recoveries, meaning that the split of work in 2024 between capital, WFO, and operations, maintenance and administration activities resulted in a higher proportion of capital work than planned.
- **Corporate Costs** were $2.3M higher than the 2024 Bridge, primarily due to increased property insurance premiums.

6. COST ALLOCATION

Hydro Ottawa has updated a cost allocation model for each of the Test years 2026-2030, and are included as Excel Attachments 1-Staff-1(H) through (L). The updated cost allocation models incorporate the addition of 2024 actuals and the move to a five year historical model (2020-2024) for demand profiles; the correction of a computational error in the original submission's calculation

of demand profiles for the years 2027 to 2030; and the conversion of Street Lights profiles to an averaging model from a trend model.[15]

Tables Q to U below detail the impact of these adjustments to the original allocation of the proposed Revenue Requirement amount. The result is a decrease in Revenue Requirement of $15.0M to Residential and $5.2M to Large Use, with offsets to the General Service customer classes and Street Lights, over the five years of the Test period. The original presentation of this data can be found in Tab 01 of Attachments 7-1-1(A) through (E) - OEB Workform Cost Allocation Models.

[15] Please see 7-Staff-195 for a full discussion.

Table Q - Revenue Requirement Impact of Updated Demand Profile 2026

Class	2026 Revenue Requirement (Row 40)					
	2026 Original Submission		2026 Updated Demand Profiles		Difference	
Residential	$184,557,521	*59.54%*	$182,033,557	*58.72%*	$ (2,523,965)	*(0.81)%*
GS <50kW	$29,976,373	*9.67%*	$30,003,267	*9.68%*	$ 26,894	*0.01%*
GS 50-1499kW	$67,596,059	*21.81%*	$69,379,624	*22.38%*	$ 1,783,566	*0.58%*
GS 1500-4999kW	$14,751,565	*4.76%*	$15,418,449	*4.97%*	$ 666,884	*0.22%*
Large Use	$10,692,863	*3.45%*	$10,715,183	*3.46%*	$ 22,320	*0.01%*
StreetLights	$1,164,116	*0.38%*	$1,200,183	*0.39%*	$ 36,067	*0.01%*
Sentinel Lights	$11,155	-	$11,115	-	$ (40)	-
USL	$883,474	*0.28%*	$880,925	*0.28%*	$ (2,549)	-
Standby GS 50-1,499 kW	$119,878	*0.04%*	$117,034	*0.04%*	$ (2,844)	-
Standby GS 1,500-4,999 kW	$32,437	*0.01%*	$31,388	*0.01%*	$ (1,049)	-
Standby Large Use	$207,879	*0.07%*	$202,595	*0.07%*	$ (5,284)	-
Total	**$309,993,321**	***100.00%***	**$309,993,321**	***100.00%***	**-**	**-**

Table R - Revenue Requirement Impact of Updated Demand Profile 2027

Class	2027 Revenue Requirement (Row 40)					
	2027 Original Submission		2027 Updated Demand Profiles		Difference	
Residential	$199,609,663	*59.51%*	$196,401,157	*58.55%*	$ (3,208,507)	*(0.96)%*
GS <50kW	$32,282,343	*9.62%*	$32,527,464	*9.70%*	$ 245,121	*0.07%*
GS 50-1499kW	$72,729,159	*21.68%*	$75,083,165	*22.38%*	$ 2,354,006	*0.70%*
GS 1500-4999kW	$15,807,893	*4.71%*	$16,504,649	*4.92%*	$ 696,756	*0.21%*
Large Use	$12,405,774	*3.70%*	$12,292,134	*3.66%*	$ (113,640)	*(0.03)%*
StreetLights	$1,249,811	*0.37%*	$1,289,893	*0.38%*	$ 40,081	*0.01%*
Sentinel Lights	$11,516	-	$11,457	-	$ (59)	-
USL	$961,829	*0.29%*	$958,136	*0.29%*	$ (3,693)	-
Standby GS 50-1,499 kW	$127,718	*0.04%*	$124,569	*0.04%*	$ (3,149)	-
Standby GS 1,500-4,999 kW	$34,249	*0.01%*	$33,101	*0.01%*	$ (1,148)	-
Standby Large Use	$219,780	*0.07%*	$214,011	*0.06%*	$ (5,769)	-
Total	**$335,439,735**	***100.00%***	**$335,439,735**	***100.00%***	**-**	**-**

Table S - Revenue Requirement Impact of Updated Demand Profile 2028

Class	2028 Revenue Requirement (Row 40)					
	2028 Original Submission		2028 Updated Demand Profiles		Difference	
Residential	214,864,359	*59.15%*	211,761,625	*58.29%*	$ (3,102,734)	*(0.85)%*
GS <50kW	34,597,865	*9.52%*	34,993,107	*9.63%*	$ 395,242	*0.11%*
GS 50-1499kW	77,849,751	*21.43%*	80,779,789	*22.24%*	$ 2,930,038	*0.81%*
GS 1500-4999kW	16,841,790	*4.64%*	17,474,504	*4.81%*	$ 632,714	*0.17%*
Large Use	16,344,570	*4.50%*	15,458,717	*4.26%*	$ (885,853)	*(0.24)%*
StreetLights	1,330,865	*0.37%*	1,376,669	*0.38%*	$ 45,805	*0.01%*
Sentinel Lights	11,762	-	11,693	-	$ (69)	-
USL	1,040,164	*0.29%*	1,036,107	*0.29%*	$ (4,056)	-
Standby GS 50-1,499 kW	134,237	*0.04%*	130,729	*0.04%*	$ (3,508)	-
Standby GS 1,500-4,999 kW	35,612	*0.01%*	34,341	*0.01%*	$ (1,270)	-
Standby Large Use	228,468	*0.06%*	222,159	*0.06%*	$ (6,309)	-
Total	**363,279,442**	***100.00%***	**363,279,442**	***100.00%***	**-**	**-**

Table T - Revenue Requirement Impact of Updated Demand Profile 2029

Class	2029 Revenue Requirement (Row 40)					
	2029 Original Submission		2029 Updated Demand Profiles		Difference	
Residential	$228,539,210	*59.00%*	$225,020,574	*58.10%*	$ (3,518,637)	*(0.91)%*
GS <50kW	$36,535,337	*9.43%*	$37,164,376	*9.59%*	$ 629,039	*0.16%*
GS 50-1499kW	$81,524,623	*21.05%*	$85,117,262	*21.98%*	$ 3,592,639	*0.93%*
GS 1500-4999kW	$17,490,603	*4.52%*	$18,183,877	*4.69%*	$ 693,275	*0.18%*
Large Use	$20,294,871	*5.24%*	$18,872,253	*4.87%*	$ (1,422,618)	*(0.37)%*
StreetLights	$1,407,173	*0.36%*	$1,454,500	*0.38%*	$ 47,327	*0.01%*
Sentinel Lights	$11,978	-	$11,839	-	$ (139)	-
USL	$1,116,662	*0.29%*	$1,109,478	*0.29%*	$ (7,184)	-
Standby GS 50-1,499 kW	$138,368	*0.04%*	$134,969	*0.03%*	$ (3,399)	-
Standby GS 1,500-4,999 kW	$36,427	*0.01%*	$35,174	*0.01%*	$ (1,252)	-
Standby Large Use	$236,154	*0.06%*	$227,103	*0.06%*	$ (9,051)	-
Total	**$387,331,405**	***100.00%***	**$387,331,405**	***100.00%***	**-**	**-**

Table U - Revenue Requirement Impact of Updated Demand Profile 2030

Class	2030 Revenue Requirement (Row 40)					
	2030 Original Submission		2030 Updated Demand Profiles		Difference	
Residential	$243,094,309	*59.09%*	$240,415,509	*58.44%*	$ (2,678,801)	*(0.65)%*
GS <50kW	$38,549,729	*9.37%*	$39,448,697	*9.59%*	$ 898,968	*0.22%*
GS 50-1499kW	$85,034,493	*20.67%*	$89,074,509	*21.65%*	$ 4,040,017	*0.98%*
GS 1500-4999kW	$18,110,417	*4.40%*	$18,675,198	*4.54%*	$ 564,780	*0.14%*
Large Use	$23,481,221	*5.71%*	$20,624,230	*5.01%*	$ (2,856,991)	*(0.69)%*
StreetLights	$1,481,996	*0.36%*	$1,537,481	*0.37%*	$ 55,485	*0.01%*
Sentinel Lights	$12,252	-	$12,131	-	$ (121)	-
USL	$1,198,670	*0.29%*	$1,191,880	*0.29%*	$ (6,791)	-
Standby GS 50-1,499 kW	$144,241	*0.04%*	$140,763	*0.03%*	$ (3,478)	-
Standby GS 1,500-4,999 kW	$37,757	*0.01%*	$36,485	*0.01%*	$ (1,273)	-
Standby Large Use	$247,001	*0.06%*	$235,206	*0.06%*	$ (11,795)	-
Total	**$411,392,088**	***100.00%***	**$411,392,088**	***100.00%***	**-**	**-**

The adjustments to Residential and GS < 50 kWh lower the revenue-to-cost ratios at Status Quo for those two classes with offsetting increases to the ratios for GS 50-1,499 kW, GS 1,500-4,999 kW, and Large Use. Tables V and W provide changes to the proposed revenue-to-cost ratios at status quo and proposed adjusted revenue-to-cost ratios. The original presentation of this data can be found in Tables 7 and 8 of Schedule 7-1-1 - Cost Allocation.

Table V - Proposed Revenue-to-Cost at Status Quo Impact of Demand Profile Correction 2027- 2030

Rate Class	Revenue / Cost Ratios at Status Quo										Policy Range
	Proposed 2026		Proposed 2027		Proposed 2028		Proposed 2029		Proposed 2030		
	Original	Updated Demand Profile	Original	Updated Demand Profile	Original	Updated Demand Profile	Original	Updated Demand Profile	Original	Updated Demand Profile	
Residential	98.18%	99.60%	98.45%	100.10%	98.98%	100.50%	99.20%	100.80%	99.20%	100.40%	85-115
GS <50kW	120.59%	119.86%	119.92%	119.02%	120.57%	119.21%	119.90%	118.52%	119.81%	117.83%	80-120
GS 50-1499kW	95.53%	93.00%	95.13%	92.10%	95.28%	91.80%	95.77%	91.60%	96.52%	92.00%	80-120
GS 1500-4999kW	103.75%	99.20%	103.07%	98.70%	103.27%	99.50%	104.05%	100.00%	104.96%	101.80%	80-120
Large Use	91.13%	93.60%	92.95%	95.50%	86.26%	91.40%	84.52%	89.70%	82.70%	92.70%	85-115
StreetLights	151.40%	137.00%	146.66%	126.10%	130.27%	123.80%	127.79%	121.60%	125.00%	120.00%	80-120
Sentinel Lights	94.11%	93.50%	87.51%	93.60%	88.30%	94.40%	90.17%	96.90%	91.50%	97.90%	80-120
USL	124.67%	120.00%	120.16%	120.00%	120.62%	120.00%	119.75%	120.00%	119.23%	119.30%	80-120
Standby GS 50-1,499 kW	37.06%	48.90%	48.15%	49.60%	49.36%	50.90%	50.52%	52.00%	51.01%	52.50%	
Standby GS 1,500-4,999 kW	51.25%	65.00%	63.55%	66.10%	65.29%	68.10%	66.81%	69.60%	67.34%	70.10%	
Standby Large Use	43.22%	56.30%	55.29%	58.80%	59.01%	61.60%	61.50%	63.60%	62.20%	64.60%	

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Table W - Proposed Adjusted Revenue-to-Cost Impact of Demand Profile Correction 2027-2030

Rate Class	Adjusted Revenue / Cost Ratios										Policy Range
	Proposed 2026		Proposed 2027		Proposed 2028		Proposed 2029		Proposed 2030		
	Original	Updated Demand Profile	Original	Updated Demand Profile	Original	Updated Demand Profile	Original	Updated Demand Profile	Original	Updated Demand Profile	
Residential	98.18%	99.57%	98.40%	100.06%	98.98%	100.46%	99.20%	100.80%	99.20%	100.36%	85-115
GS <50kW	119.92%	119.83%	120.00%	119.05%	119.90%	119.23%	119.90%	118.60%	119.00%	117.75%	80-120
GS 50-1499kW	95.53%	93.03%	95.10%	92.14%	95.28%	91.75%	95.77%	91.63%	96.52%	92.03%	80-120
GS 1500-4999kW	103.75%	99.21%	103.10%	98.73%	103.27%	99.50%	104.05%	100.05%	104.20%	101.77%	80-120
Large Use	93.51%	93.63%	94.80%	95.49%	87.80%	91.40%	85.00%	89.74%	85.00%	92.68%	85-115
StreetLights	145.12%	137.04%	128.30%	126.14%	126.80%	123.83%	123.90%	121.62%	120.00%	120.00%	80-120
Sentinel Lights	87.39%	93.52%	87.50%	93.65%	88.30%	94.45%	90.17%	96.88%	91.50%	97.94%	80-120
USL	119.97%	119.97%	120.00%	120.07%	120.10%	120.07%	119.75%	120.01%	118.40%	119.34%	80-120
Standby GS 50-1,499 kW	47.71%	48.86%	48.30%	49.56%	49.50%	50.91%	50.60%	51.98%	51.10%	52.46%	
Standby GS 1,500-4,999 kW	62.72%	65.05%	63.60%	66.10%	65.29%	68.12%	66.81%	69.62%	66.90%	70.13%	
Standby Large Use	54.68%	56.27%	57.50%	58.76%	60.90%	61.61%	62.40%	63.59%	64.50%	64.58%	

Some minor updates to the models were made to address changes resulting from the responses to interrogatories 7-Staff-195 (Streetlight demand factors switching to the average methodology instead of trend methodology) and 7-VECC-52 (vendors misidentified in the calculation of the Billing and Collecting weighting factors). Tables X to AB below detail the impact of the adjustments on Revenue Requirement allocation for each year of the rate period. Note that the impact of the change to Streetlight demand factors is also included in Tables Q to U above, which summarize the impact of all changes to the demand profiles.

Table X - Cost Allocation Impact of Streetlight Demand Factor and Billing and Collecting Weighting Factors Corrections - 2026

Rate Class	7-Staff-195	7-VECC-52	Total
Residential	$ (15,875)	$ (2,921)	**$ (18,796)**
GS <50	$ 17,493	$ (420)	**$ 17,073**
GS 50 to 1,499 kW	$ 2,015	$ (685)	**$ 1,330**
GS 1,500 to 4,999 kW	$ (3,719)	$ (149)	**$ (3,868)**
Large Use	$ (586)	$ (100)	**$ (686)**
Street Light	$ 245	$ 4,301	**$ 4,546**
Sentinel	$ 114	$ (0)	**$ 113**
Unmetered Scattered Load	$ 773	$ (21)	**$ 752**
Standby Power GS 50 to 1,499 kW	$ (153)	$ (2)	**$ (155)**
Standby Power GS 1,500 to 4,999 kW	$ (153)	$ (0)	**$ (153)**
Standby Power Large Use	$ (153)	$ (3)	**$ (156)**

Table Y - Cost Allocation Impact of Streetlight Demand Factor and Billing and Collecting Weighting Factor Corrections - 2027

Rate Class	7-Staff-195	7-VECC-52	Total
Residential	$ (30,499)	$ (3,910)	**$ (34,409)**
GS <50	$ 20,140	$ (568)	**$ 19,573**
GS 50 to 1,499 kW	$ 13,939	$ (906)	**$ 13,033**
GS 1,500 to 4,999 kW	$ (3,794)	$ (194)	**$ (3,988)**
Large Use	$ (662)	$ (142)	**$ (804)**
Street Light	$ 301	$ 5,756	**$ 6,057**
Sentinel	$ 138	$ (0)	**$ 138**
Unmetered Scattered Load	$ 940	$ (29)	**$ 911**
Standby Power GS 50 to 1,499 kW	$ (168)	$ (2)	**$ (170)**
Standby Power GS 1,500 to 4,999 kW	$ (168)	$ (1)	**$ (169)**
Standby Power Large Use	$ (168)	$ (4)	**$ (172)**

Table Z -Cost Allocation Impact of Streetlight Demand Factor and Billing and Collecting Weighting Factor Corrections - 2028

Rate Class	7-Staff-195	7-VECC-52	Total
Residential	$ (49,282)	$ (4,958)	**$ (54,239)**
GS <50	$ 23,549	$ (724)	**$ 22,825**
GS 50 to 1,499 kW	$ 29,172	$ (1,120)	**$ 28,052**
GS 1,500 to 4,999 kW	$ (3,830)	$ (237)	**$ (4,067)**
Large Use	$ (724)	$ (218)	**$ (942)**
Street Light	$ 364	$ 7,301	**$ 7,665**
Sentinel	$ 161	$ (0)	**$ 160**
Unmetered Scattered Load	$ 1,134	$ (37)	**$ 1,096**
Standby Power GS 50 to 1,499 kW	$ (181)	$ (2)	**$ (183)**
Standby Power GS 1,500 to 4,999 kW	$ (181)	$ (1)	**$ (182)**
Standby Power Large Use	$ (181)	$ (4)	**$ (185)**

Table AA - Cost Allocation Impact of Streetlight Demand Factor and Billing and Collecting Weighting Factor Corrections - 2029

Rate Class	7-Staff-195	7-VECC-52	Total
Residential	$ (78,288)	$ (6,131)	**$ (84,419)**
GS <50	$ 26,434	$ (902)	**$ 25,531**
GS 50 to 1,499 kW	$ 54,801	$ (1,344)	**$ 53,456**
GS 1,500 to 4,999 kW	$ (3,650)	$ (279)	**$ (3,929)**
Large Use	$ (744)	$ (315)	**$ (1,059)**
Street Light	$ 452	$ 9,029	**$ 9,481**
Sentinel	$ 186	$ (0)	**$ 185**
Unmetered Scattered Load	$ 1,390	$ (47)	**$ 1,343**
Standby Power GS 50 to 1,499 kW	$ (193)	$ (3)	**$ (196)**
Standby Power GS 1,500 to 4,999 kW	$ (193)	$ (1)	**$ (194)**
Standby Power Large Use	$ (193)	$ (5)	**$ (198)**

Table AB - Cost Allocation Impact of Streetlight Demand Factor and Billing and Collecting Weighting Factor Corrections - 2030

Rate Class	7-Staff-195	7-VECC-52	Total
Residential	$ (115,681)	$ (7,511)	**$ (123,192)**
GS <50	$ 30,948	$ (1,116)	**$ 29,832**
GS 50 to 1,499 kW	$ 86,888	$ (1,614)	**$ 85,273**
GS 1,500 to 4,999 kW	$ (3,342)	$ (330)	**$ (3,671)**
Large Use	$ (682)	$ (417)	**$ (1,099)**
Street Light	$ 558	$ 11,057	**$ 11,615**
Sentinel	$ 221	$ (1)	**$ 221**
Unmetered Scattered Load	$ 1,704	$ (58)	**$ 1,646**
Standby Power GS 50 to 1,499 kW	$ (205)	$ (4)	**$ (208)**
Standby Power GS 1,500 to 4,999 kW	$ (205)	$ (1)	**$ (206)**
Standby Power Large Use	$ (205)	$ (6)	**$ (211)**

The models have also been updated to incorporate changes discussed elsewhere in this document: the ADMS program timing (Section 4.1 Capital), PILS (Section 2.2 Payment in Lieu of Taxes (PILS)), rate base (Section 4.4 Rate base), and Revenue Requirements (Section 2. Revenue Requirement). These changes have reduced Revenue Requirement in total for each of the five years as detailed in Table AC below. Changes to Depreciation and to PILS (include PILs capital contribution) account for more than 93% of the reduction, primarily in the first two years of the rate application period. The remaining update on cost of capital is due to the change in rate base outlined in Section 4.

Table AC - Changes to Proposed Revenue Requirement 2026-2030

Year	Original Submission	1-Staff-1	Total Difference	Difference by Component			
				Depreciation and Amortization	PILs	Interest	Allocated Net Income
2026	$ 309,993,321	$ 308,188,282	$ (1,805,039)	$ (1,104,616)	$ (9,665)	$ (274,499)	$ (416,259)
2027	$ 335,439,736	$ 331,195,640	$ (4,244,096)	$ (862,883)	$ (3,182,457)	$ (78,983)	$ (119,773)
2028	$ 363,279,442	$ 362,772,077	$ (507,365)	$ (14,048)	$ (636,738)	$ 56,993	$ 86,427
2029	$ 387,331,405	$ 387,206,321	$ (125,084)	$ (14,048)	$ (255,295)	$ 57,327	$ 86,932
2030	$ 411,392,088	$ 411,346,473	$ (45,615)	$ (94,395)	$ (98,719)	$ 58,615	$ 88,884

Tables AD to AH detail those reductions by customer class for each year. Over the five year period, Residential proposed Revenue Requirement is reduced by $18.3M and Large use by $5.5M. The offsetting increases mainly impact the general service classes.

Table AD - Updated Revenue Requirement by Customer Class 2026[16]

Class	2026 Revenue Requirement (Row 40)					
	2026 Original Submission		Attachment 1-Staff-1 (H)		Difference	
Residential	$184,557,521	*59.54%*	$180,937,198	*58.71%*	$ (3,620,324)	*(0.83)%*
GS <50kW	$29,976,373	*9.67%*	$29,834,681	*9.68%*	$ (141,692)	*0.01%*
GS 50-1499kW	$67,596,059	*21.81%*	$68,996,850	*22.39%*	$ 1,400,791	*0.58%*
GS 1500-4999kW	$14,751,565	*4.76%*	$15,331,277	*4.97%*	$ 579,712	*0.22%*
Large Use	$10,692,863	*3.45%*	$10,657,229	*3.46%*	$ (35,635)	*0.01%*
StreetLights	$1,164,116	*0.38%*	$1,194,080	*0.39%*	$ 29,964	*0.01%*
Sentinel Lights	$11,155	-	$11,174	-	$ 18	-
USL	$883,474	*0.28%*	$876,905	*0.28%*	$ (6,569)	-
Standby GS 50-1,499 kW	$119,878	*0.04%*	$116,318	*0.04%*	$ (3,560)	-
Standby GS 1,500-4,999 kW	$32,437	*0.01%*	$31,089	*0.01%*	$ (1,348)	-
Standby Large Use	$207,879	*0.07%*	$201,482	*0.07%*	$ (6,397)	-
Total	**$309,993,321**	***100.00%***	**$308,188,282**	***100.00%***	**$ (1,805,039)**	**-**

[16] Values may not tie to RRWF due to rounding.

Table AE - Updated Revenue Requirement by Customer Class 2027[17]

Class	2027 Revenue Requirement (Row 40)					
	2027 Original Submission		Attachment 1-Staff-1 (I)		Difference	
Residential	$199,609,663	*59.51%*	$193,946,987	*58.56%*	$ (5,662,676)	*(0.95)%*
GS <50kW	$32,282,343	*9.62%*	$32,122,131	*9.70%*	$ (160,212)	*0.07%*
GS 50-1499kW	$72,729,159	*21.68%*	$74,111,600	*22.38%*	$ 1,382,441	*0.70%*
GS 1500-4999kW	$15,807,893	*4.71%*	$16,284,473	*4.92%*	$ 476,580	*0.20%*
Large Use	$12,405,774	*3.70%*	$12,131,520	*3.66%*	$ (274,254)	*(0.04)%*
StreetLights	$1,249,811	*0.37%*	$1,273,877	*0.38%*	$ 24,066	*0.01%*
Sentinel Lights	$11,516	-	$11,466	-	$ (49)	-
USL	$961,829	*0.29%*	$947,219	*0.29%*	$ (14,610)	-
Standby GS 50-1,499 kW	$127,718	*0.04%*	$122,786	*0.04%*	$ (4,932)	-
Standby GS 1,500-4,999 kW	$34,249	*0.01%*	$32,510	*0.01%*	$ (1,739)	-
Standby Large Use	$219,780	*0.07%*	$211,070	*0.06%*	$ (8,710)	-
Total	**$335,439,735**	***100.00%***	**$331,195,640**	***100.00%***	**$ (4,244,096)**	**-**

[17] Values may not tie to RRWF due to rounding.

Table AF - Updated Revenue Requirement by Customer Class 2028[18]

Class	2028 Revenue Requirement (Row 40)					
	2028 Original Submission		Attachment 1-Staff-1 (J)		Difference	
Residential	$214,864,359	*59.15%*	$211,387,717	*58.27%*	$ (3,476,642)	*(0.88)%*
GS <50kW	$34,597,865	*9.52%*	$34,957,618	*9.64%*	$ 359,753	*0.11%*
GS 50-1499kW	$77,849,751	*21.43%*	$80,722,558	*22.25%*	$ 2,872,807	*0.82%*
GS 1500-4999kW	$16,841,790	*4.64%*	$17,452,697	*4.81%*	$ 610,907	*0.17%*
Large Use	$16,344,570	*4.50%*	$15,441,106	*4.26%*	$ (903,465)	*(0.24)%*
StreetLights	$1,330,865	*0.37%*	$1,375,849	*0.38%*	$ 44,985	*0.01%*
Sentinel Lights	$11,762	-	$11,847	-	$ 85	-
USL	$1,040,164	*0.29%*	$1,036,685	*0.29%*	$ (3,479)	-
Standby GS 50-1,499 kW	$134,237	*0.04%*	$130,327	*0.04%*	$ (3,910)	-
Standby GS 1,500-4,999 kW	$35,612	*0.01%*	$34,098	*0.01%*	$ (1,513)	-
Standby Large Use	$228,468	*0.06%*	$221,574	*0.06%*	$ (6,894)	-
Total	**$363,279,442**	***100.00%***	**$362,772,076**	***100.00%***	**$ (507,366)**	**-**

[18] Values may not tie to RRWF due to rounding.

Table AG - Updated Revenue Requirement by Customer Class 2029[19]

Class	2029 Revenue Requirement (Row 40)					
	2029 Original Submission		Attachment 1-Staff-1 (K)		Difference	
Residential	$228,539,210	*59.00%*	$224,832,818	*58.07%*	$ (3,706,393)	*(0.94)%*
GS <50kW	$36,535,337	*9.43%*	$37,169,347	*9.60%*	$ 634,010	*0.17%*
GS 50-1499kW	$81,524,623	*21.05%*	$85,176,650	*22.00%*	$ 3,652,027	*0.95%*
GS 1500-4999kW	$17,490,603	*4.52%*	$18,181,981	*4.70%*	$ 691,379	*0.18%*
Large Use	$20,294,871	*5.24%*	$18,870,500	*4.87%*	$ (1,424,371)	*(0.37)%*
StreetLights	$1,407,173	*0.36%*	$1,455,215	*0.38%*	$ 48,042	*0.01%*
Sentinel Lights	$11,978	-	$12,028	-	$ 51	-
USL	$1,116,662	*0.29%*	$1,111,401	*0.29%*	$ (5,261)	-
Standby GS 50-1,499 kW	$138,368	*0.04%*	$134,691	*0.03%*	$ (3,677)	-
Standby GS 1,500-4,999 kW	$36,427	*0.01%*	$34,954	*0.01%*	$ (1,473)	-
Standby Large Use	$236,154	*0.06%*	$226,737	*0.06%*	$ (9,417)	-
Total	**$387,331,405**	***100.00%***	**$387,206,321**	***100.00%***	**$ (125,084)**	**-**

[19] Values may not tie to RRWF due to rounding

Table AH - Updated Revenue Requirement by Customer Class 2030[20]

Class	2030 Revenue Requirement (Row 40)					
	2030 Original Submission		Attachment 1-Staff-1 (L)		Difference	
Residential	$243,094,309	*59.09%*	$240,238,610	*58.40%*	$ (2,855,700)	*(0.69)%*
GS <50kW	$38,549,729	*9.37%*	$39,466,243	*9.59%*	$ 916,514	*0.22%*
GS 50-1499kW	$85,034,493	*20.67%*	$89,183,496	*21.68%*	$ 4,149,003	*1.01%*
GS 1500-4999kW	$18,110,417	*4.40%*	$18,677,058	*4.54%*	$ 566,640	*0.14%*
Large Use	$23,481,221	*5.71%*	$20,624,216	*5.01%*	$ (2,857,006)	*(0.69)%*
StreetLights	$1,481,996	*0.36%*	$1,538,548	*0.37%*	$ 56,552	*0.01%*
Sentinel Lights	$12,252	-	$12,357	-	$ 105	-
Standby GS 50-1,499 kW	$1,198,670	*0.29%*	$1,194,312	*0.29%*	$ (4,358)	-
Standby GS 1,500-4,999 kW	$144,241	*0.04%*	$140,501	*0.03%*	$ (3,740)	-
Standby Large Use	$37,757	*0.01%*	$36,260	*0.01%*	$ (1,498)	-
Standby LU	$247,001	*0.06%*	$234,874	*0.06%*	$ (12,127)	-
Total	**$411,392,088**	***100.00%***	**$411,346,473**	***100.00%***	**$ (45,615)**	**-**

[20] Values may not tie to RRWF due to rounding.

Tables AI and AJ detail the impact on revenue-to-cost ratios, at status quo and adjusted, of all changes discussed above.

Table AI - Impact of Updated Revenue Requirement and Modelling Changes at Status Quo Rates

Rate Class	Revenue / Cost Ratios at Status Quo										Policy Range
	Proposed 2026		Proposed 2027		Proposed 2028		Proposed 2029		Proposed 2030		
	Original	1-Staff-1	Original	1-Staff-1	Original	1-Staff-1	Original	1-Staff-1	Original	1-Staff-1	
Residential	98.18%	99.60%	98.45%	100.10%	98.98%	100.50%	99.20%	100.80%	99.20%	100.40%	85-115
GS <50kW	120.59%	119.86%	119.92%	119.02%	120.57%	119.21%	119.90%	118.52%	119.81%	117.83%	80-120
GS 50-1,499 kW	95.53%	93.00%	95.13%	92.10%	95.28%	91.80%	95.77%	91.60%	96.52%	92.00%	80-120
GS 1,500-4,999 kW	103.75%	99.20%	103.07%	98.70%	103.27%	99.50%	104.05%	100.00%	104.96%	101.80%	80-120
Large Use	91.13%	93.60%	92.95%	95.50%	86.26%	91.40%	84.52%	89.70%	82.70%	92.70%	85-115
StreetLights	151.40%	137.00%	146.66%	126.10%	130.27%	123.80%	127.79%	121.60%	125.00%	120.00%	80-120
Sentinel Lights	94.11%	93.50%	87.51%	93.60%	88.30%	94.40%	90.17%	96.90%	91.50%	97.90%	80-120
USL	124.67%	120.00%	120.16%	120.00%	120.62%	120.00%	119.75%	120.00%	119.23%	119.30%	80-120
Standby GS 50-1,499 kW	37.06%	48.90%	48.15%	49.60%	49.36%	50.90%	50.52%	52.00%	51.01%	52.50%	
Standby GS 1,500-4,999 kW	51.25%	65.00%	63.55%	66.10%	65.29%	68.10%	66.81%	69.60%	67.34%	70.10%	
Standby Large Use	43.22%	56.30%	55.29%	58.80%	59.01%	61.60%	61.50%	63.60%	62.20%	64.60%	

Table AJ - Impact of Updated Revenue Requirement and Modelling Changes at Adjusted Rates

Rate Class	Adjusted Revenue / Cost Ratios										Policy Range
	Proposed 2026		Proposed 2027		Proposed 2028		Proposed 2029		Proposed 2030		
	Original	1-Staff-1	Original	1-Staff-1	Original	1-Staff-1	Original	1-Staff-1	Original	1-Staff-1	
Residential	98.18%	99.57%	98.40%	100.06%	98.98%	100.46%	99.20%	100.80%	99.20%	100.36%	85-115
GS <50kW	119.92%	119.83%	120.00%	119.05%	119.90%	119.23%	119.90%	118.60%	119.00%	117.75%	80-120
GS 50-1,499 kW	95.53%	93.03%	95.10%	92.14%	95.28%	91.75%	95.77%	91.63%	96.52%	92.03%	80-120
GS 1,500-4,999 kW	103.75%	99.21%	103.10%	98.73%	103.27%	99.50%	104.05%	100.05%	104.20%	101.77%	80-120
Large Use	93.51%	93.63%	94.80%	95.49%	87.80%	91.40%	85.00%	89.74%	85.00%	92.68%	85-115
StreetLights	145.12%	137.04%	128.30%	126.14%	126.80%	123.83%	123.90%	121.62%	120.00%	120.00%	80-120
Sentinel Lights	87.39%	93.52%	87.50%	93.65%	88.30%	94.45%	90.17%	96.88%	91.50%	97.94%	80-120
USL	119.97%	119.97%	120.00%	120.07%	120.10%	120.07%	119.75%	120.01%	118.40%	119.34%	80-120
Standby GS 50-1,499 kW	47.71%	48.86%	48.30%	49.56%	49.50%	50.91%	50.60%	51.98%	51.10%	52.46%	
Standby GS 1,500-4,999 kW	62.72%	65.05%	63.60%	66.10%	65.29%	68.12%	66.81%	69.62%	66.90%	70.13%	
Standby Large Use	54.68%	56.27%	57.50%	58.76%	60.90%	61.61%	62.40%	63.59%	64.50%	64.58%	

6.1 ADJUSTMENTS TO COST ALLOCATION RESULTS - REVENUE TO COST RATIOS

The results from the updated 2026 cost allocation show that there are two rate classes that require adjustments to bring them within the OEB-Approved ranges: Street Lighting and Unmetered Scattered Load. Both of these rate classes are above the Revenue/Cost ratio upper limit of 120%. Hydro Ottawa has applied the same approach as originally proposed, in Section 9.1 of Schedule 7-1-1 - Cost Allocation, to bring the Unmetered Scattered Load within the OEB-Approved range in 2026, and bring the Street Light class within the upper limit of 120% by 2030. All offsetting adjustments are being applied to the Large User class.

As part of the updates the Sentinel Lighting class total bill impact is now under 10%, resulting in no need for proposed rate mitigation.

7. RETAIL TRANSMISSION AND LOW VOLTAGE SERVICE RATES

Hydro Ottawa has submitted an updated RTSR Workform using 2024 RRR data and 2024 Historical Wholesale amounts. Attachment 1-Staff-1(D) - 2026 RTSR Workform EV also includes the proposed 2026 RTSR rates for EV Charging.

In alignment with the updated Guideline for Electricity Distribution Retail Transmission Service Rates and Low Voltage Charges[21] Hydro Ottawa has also updated the allocation based on each rate class's contribution to 12 CP from the Demand Profiles used in the 2026 Cost Allocation Model. The proposed 2026-2030 Low Voltage (LV) rates have also been updated based on the updated RTSR Connection rates.

The following changes were made to the OEB's 2026 RTSR model for the purpose of this application:

- On Tab 4. UTRs and Sub-Transmission; 2026 Estimate rates were added in column L and the 2025 rates in column I were replaced with 2025 approved rates;

[21] Ontario Energy Board, *Guideline Electricity Distribution Retail Transmission Service Rates and Low Voltage Charges* (March 31, 2025) Page 5

- On Tab 8. RTSR Rates to Forecast, Column H rows 45 to 55 and rows 59 to 68 were manually updated to the 12 CP percentage allocation; and
- Four additional tabs (Tab 10 - Tab 13) were created to calculate the low voltage rates for Test Years 2027-2030.

The updated RTSR and LV rates have been included in the Bill Impacts presented in Table AL as well as Attachment 1-Staff-1(F) - OEB Workform - 2025 Current and 2026 Proposed Tariff of Rates and Charges and Attachment 1-Staff-1(G) - 2026-2030 Bill Impacts.

8. LOSS FACTORS

OEB Appendix 2-R - Loss Factors has been updated to include 2024 Historicals. As a result, Hydro Ottawa is requesting approval of revised loss factors, based on the five-year average ending in 2024, for Secondary and Primary Metered Customers. Table AK summarizes the revised Loss Adjustment Factors.

Table AK - Updated Proposed Loss Adjustment Factors

Total Loss Factor	Original	Updated	Variance
Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0332	1.0335	0.0003
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0151	1.0150	- 0.0001
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0229	1.0231	0.0002
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0049	1.0048	- 0.0001

9. BILL IMPACTS SUMMARY

Table AL below provides an Updated summary of the total bill impacts for typical customers in all classes. Additional bill impacts have been provided in Attachment 1-Staff-1(F) - OEB Workform - 2025 Current and 2026 Proposed Tariff of Rates and Charges and Attachment 1-Staff-1(G) - 2026-2030 Bill Impacts Model. The original presentation of this data can be found in Table 1 of Schedule 8-5-1 - Bill Impacts and Tariff of Rates and Charges.

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Table AL - Summary of Bill Impacts

Rate Class		Approved	Proposed				
		2025	2026	2027	2028	2029	2030
Residential (750 kWh)	Distribution Charge	$34.51	$40.34	$43.80	$47.62	$50.40	$53.15
	Change in Distribution Charge		$5.83	$3.46	$3.82	$2.78	$2.75
	% Distribution Increase		16.89%	8.58%	8.72%	5.84%	5.46%
	% Increase of Total Bill		6.60%	2.53%	2.68%	1.90%	1.85%
General Service <50 kW (2000 kWh)	Distribution Charge	$85.93	$99.94	$107.53	$116.94	$123.84	$130.52
	Change in Distribution Charge		$14.01	$7.59	$9.41	$6.90	$6.68
	% Distribution Increase		16.30%	7.59%	8.75%	5.90%	5.39%
	% Increase of Total Bill		3.29%	2.15%	2.61%	1.87%	1.78%
General Service 50 kW - 1,499 kW (185 kW)	Distribution Charge	$1,366.91	$1,663.31	$1,811.48	$1,963.81	$2,078.47	$2,192.15
	Change in Distribution Charge		$296.41	$148.17	$152.33	$114.66	$113.68
	% Distribution Increase		21.68%	8.91%	8.41%	5.84%	5.47%
	% Increase of Total Bill		2.19%	(1.69)%	1.28%	0.95%	0.93%
General Service 1,500 kW - 4,999 kW (1,925 kW)	Distribution Charge	$16,219.02	$17,900.32	$20,311.57	$22,110.68	$23,420.45	$24,721.75
	Change in Distribution Charge		$1,681.30	$2,411.26	$1,799.11	$1,309.77	$1,301.30
	% Distribution Increase		10.37%	13.47%	8.86%	5.92%	5.56%
	% Increase of Total Bill		0.36%	(1.24)%	1.32%	0.95%	0.94%
Large Use (7,500 kW)	Distribution Charge	$61,692.18	$69,297.93	$80,277.18	$87,603.93	$92,892.93	$98,013.18
	Change in Distribution Charge		$7,605.75	$10,979.25	$7,326.75	$5,289.00	$5,120.25
	% Distribution Increase		12.33%	15.84%	9.13%	6.04%	5.51%
	% Increase of Total Bill		0.97%	(1.27)%	1.25%	0.89%	0.85%
Sentinel Lighting (0.4 kW)	Distribution Charge	$20.19	$23.71	$25.81	$28.07	$29.71	$31.33
	Change in Distribution Charge		$3.52	$2.10	$2.26	$1.64	$1.63
	% Distribution Increase		17.41%	8.87%	8.75%	5.83%	5.48%
	% Increase of Total Bill		9.11%	5.95%	6.00%	4.13%	3.94%
Street Lighting (50kW)	Distribution Charge	$928.89	$956.13	$735.50	$774.77	$795.47	$823.77
	Change in Distribution Charge		$27.24	($220.63)	$39.27	$20.71	$28.30
	% Distribution Increase		2.93%	(23.07)%	5.34%	2.67%	3.56%
	% Increase of Total Bill		(2.45)%	(9.26)%	1.33%	0.69%	0.94%
Unmetered Scattered Load (470 kWh)	Distribution Charge	$22.98	$25.58	$28.06	$30.37	$32.13	$33.89
	Change in Distribution Charge		$2.61	$2.48	$2.31	$1.76	$1.76
	% Distribution Increase		11.35%	9.68%	8.22%	5.80%	5.48%
	% Increase of Total Bill		0.54%	2.93%	2.70%	2.02%	1.98%

10. DEFERRAL AND VARIANCE ACCOUNTS SUMMARY

The DVA Continuity schedule has been updated to include both Group 1 and Group 2 Accounts with the principal balances up to December 31, 2024 and interest forecasted to December 31, 2025. Refer to Attachment 1-Staff-1 (C) - OEB Workform - 2026 Deferral and Variance Accounts (Continuity Schedule).

10.1 GROUP 1 ACCOUNTS FOR WHICH HYDRO OTTAWA IS SEEKING DISPOSITION

Hydro Ottawa is requesting disposition of all of its Group 1 Accounts as presented in Attachment 1-Staff-1(C) - OEB Workform - 2026 Deferral and Variance Account (Continuity Schedule) based on December 31, 2024 audited balances and including projected interest to December 31, 2025. Table AM below provides a summary of the updated proposed Group 1 DVAs by Uniform System of Accounts (USofA) for which Hydro Ottawa is seeking disposition. Hydro Ottawa is seeking disposition of a net debit balance of $10.3M to be disposed of over a one year term.

Hydro Ottawa has provided an updated Attachment 1-Staff-1(B) - OEB Workform - 2026 Commodity Accounts Analysis using data from the 2024 audited financial statements. The unresolved difference, noted in Attachment 1-Staff-1(B), is the percentage of expected Global Adjustment (GA) is below the materiality threshold of plus or minus 10%. Hydro Ottawa received approval on a final basis to dispose of balances in Group 1 Accounts as at December 31, 2023 over a one year term as part of its 2025 Rate Application.[22]

[22] Hydro Ottawa Limited, *2025 Decision and Rate Order*, EB-2024-0035 (December 17, 2024), pages 15-16.

Table AM – Proposed Group 1 DVA Dispositions[23]

Group	USofA Number	Group 1 Deferral/Variance Account Description	Amount ($)	Principal ($)	Interest ($)
1	1550	LV Variance Account	$45,605	$43,508	$2,096
1	1551	Smart Metering Entity Charge Variance Account	$(348,243)	$(330,304)	$(17,939)
1	1580	RSVA - Wholesale Market Service Charge	$(4,276,759)	$(4,081,815)	$(194,943)
1	1580	Variance WMS - Sub-account CBR Class A	-	-	-
1	1580	Variance WMS - Sub-account CBR Class B	$2,623,768	$2,523,372	$100,396
1	1584	RSVA - Retail Transmission Network Charge	$4,977,775	$4,781,796	$195,979
1	1586	RSVA - Retail Transmission Connection Charge	$(4,383,898)	$(4,164,624)	$(219,275)
1	1588	RSVA - Power (excluding Global Adjustment)	$1,210,110	$918,243	$291,867
1	1589	RSVA - Global Adjustment	$10,839,429	$10,240,736	$598,693
1	1595	Disposition and Recovery/Refund of Regulatory Balances (2021)3	$(492,336)	$(236,907)	$(255,428)
1	1595	Disposition and Recovery/Refund of Regulatory Balances (2022)3	$141,532	$190,630	$(49,098)
		Group 1 Subtotal (Excluding Global Adjustment)	**$(502,446)**	**$(356,101)**	**$(146,345)**
		Global Adjustment	$10,839,429	$10,240,736	$598,693
	TOTAL DVA BALANCE (Group 1) TO BE MOVED TO 1595 (2026)		**$10,336,983**	**$9,884,634**	**$452,348**

10.2 GROUP 2 ACCOUNTS FOR WHICH HYDRO OTTAWA IS SEEKING DISPOSITION

Hydro Ottawa is requesting disposition of its Group 2 Accounts as presented in Attachment 1-Staff-1(C) - OEB Workform - Deferral and Variance Account (Continuity Schedule) based on December 31, 2024 audited balances (with the exception of Account 1568 with disposition to December 31, 2023) and including projected interest to December 31, 2025. Some of the balances

[23] Totals may not sum due to rounding.

have principal and interest adjustments, which have been detailed on Tab 3. 'Appendix A' of the DVA model.

Hydro Ottawa is proposing the disposition of LRAMVA balances up to December 31, 2023, with carrying charges to December 31, 2025. The LRAMVA workform has been updated to reflect a duplication error found in the persistence tab. Please see Attachment 1-Staff-1(R) - OEB LRAMVA Workform. In addition, refer to Attachment 9-Staff-219(A) for additional information on persistence savings used to calculate the LRAMVA balances. The amount in 1-Staff-1(R) - OEB LRAMVA Workform versus Attachment 9-1-5(A) - LRAMVA Workform differ by $401. See Table AN below for the details on the variance.

Hydro Ottawa will record the impact of CDM and eDSM savings for the years 2024 to 2025 in the LRAMVA once the IESO releases reports of those years.

As noted in interrogatory response 9-Staff-218, Hydro Ottawa will continue to utilize the LRAMVA to track and measure the financial impact of various CDM initiatives to the end of 2025 per Hydro Ottawa's 2021-2025 Approved Settlement Agreement.[24]

Table AN - Variance Reconciliation Between Attachment 1-Staff-1 (R) - OEB LRAMVA Workform & Attachment 9-1-5(A) OEB LRAMVA Workform

Year	9-1-5(A) Principal Claim	9-1-5(A) Interest Claim	9-Staff-219 Principal Claim	9-Staff-219 Interest Claim	Variance
2021	$ (489,039)	$ (1,277)	$ (488,879)	$ (1,277)	$ (160)
2022	$ (304,155)	$ (13,088)	$ (304,040)	$ (13,083)	$ (120)
2023	$ 208,928	$ (35,037)	$ 208,249	$ (35,039)	$ 681
Total Claim	**$ (584,266)**	**$ (49,402)**	**$ (584,670)**	**$ (49,399)**	**$ 401**

The total net credit balance of the Group 2 DVAs updated for 2024 for which Hydro Ottawa is seeking disposition is $4.6M over a one year term. The disposition amount of $4.6M includes a

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

disposition amount for LRAMVA for $(682,163).[25] The formula for the LRAMVA claim (cell BT91 on Tab '2b. Allocation of Balances') was removed and replaced with the disposition amount due to the LRAMVA only clearing balances up to 2023.

Table AO provides a summary of the Group 2 DVAs by Uniform System of Accounts (USofA) for which Hydro Ottawa is seeking disposition.

[25] Includes projected interest to December 31, 2025.

Table AO - Proposed Group 2 DVA Dispositions

Group	USofA Number	Group 2 Deferral/Variance Account Description	Amount	Principal	Interest
2	1508	Pole Attachment Revenue Variance	$ 798,947	$ 697,316	$ 101,631
2	1508	GOCA Variance Account	$ 1,078,263	$ 1,008,528	$ 69,735
2	1508	Gains and Loss on disposal of Fixed Assets Variance Account	$ (1,419,661)	$ (1,245,849)	$ (173,813)
2	1508	Earnings Sharing Mechanism (ESM) Variance Account	$ (1,349,874)	$ (1,151,693)	$ (198,181)
2	1508	Connection Cost Recovery Agreement (CCRA) Payments Differential Variance Account	$ (1,168,794)	$ (1,109,625)	$ (59,169)
2	1508	Efficiency Adjustment Mechanism (EAM) Deferral Account	$ (341,829)	$ (300,816)	$ (41,013)
2	1508	OEB Cost Assessment Variance	$ 550,744	$ 486,987	$ 63,757
2	1508	Performance Outcomes Account Mechanism (POAM) Deferral Account	$ (1,092,856)	$ (1,000,000)	$ (92,856)
2	1508	RCVA Retail Incremental Revenue	$ 53,813	$ 46,028	$ 7,785
2	1508	STR Incremental Revenue	$ 1,714	$ 1,467	$ 247
2	1508	Capital Variance Account	$ (81,982)	$ (33,313)	$ (48,669)
		Sub-Total of 1508 Sub-Accounts	**$ (2,971,515)**	**$ (2,600,970)**	**$ (370,545)**
2	1522	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	$ (229,512)	-	$ (229,512)
2	1592	PILs and Tax Variance - Sub-Account Capital Cost Allowance (CCA) Changes	$ (721,224)	$ (620,386)	$ (100,837)
		Group 2 Sub-total (Prior to Lost Revenue Adjustment Mechanism (LRAM)	**$ (3,922,251)**	**$ (3,221,357)**	**$ (700,894)**
2	1568	LRAM Variance Account (LRAMVA)	$ (682,163)	$ (584,266)	$ (97,896)
	TOTAL DVA BALANCE (Group 2) TO BE MOVED TO 1595 (2026)		**$ (4,604,414)**	**$ (3,805,623)**	**$ (798,791)**

Sub-Account - GOCA Variance Account has been updated to include balances up to December 31, 2024. The OEB-approved amount for the period April 2023 to December 31, 2025 is $5,770k and

actual costs incurred for the same period is $6,778.9k; therefore $1,008.5k of claim (principal) has been recorded into this sub-account.

Sub-Account - Gains and Loss on disposal of Fixed Assets Variance Account has been updated to include transactions in 2024. OEB-approved loss for 2024 was $336k and actual loss was $132k; therefore $204k credit has been recorded into this sub-account. The total principal balance as at December 31, 2024 is $1,245.8k.

Sub-Account - CCRA Payments Differential Variance Account has been updated to include balances up to December 31, 2024. In 2024 $543k was recorded into this sub-account: $159k related to A6R and $384k for other CCRAs.

Sub-Account - Capital Variance Account has been updated to include balances up to December 31, 2024 with a net credit of $519K to be recovered from customers resulting from the following.

- System Access Symmetrical Account of $1.6M due to capital additions exceeded approved level.
- System Access Asymmetrical Account of ($1.1M) return to ratepayers due to underspending.
- All other investment categories achieved targets.

Sub-Account - POAM has been updated to include balances up to December 31, 2024. In 2024 Hydro Ottawa recorded a credit of $200k to this account as wood pole replacement POAM metric (#4) was not met.

Sub-Account - PILs has been updated to include balances up to December 31, 2024. In 2024 Hydro Ottawa recorded a debit of $195k to record the impact of the 2021 immediate expensing for the 2021-2025 period.

There were no other principal adjustments to other group two accounts.

10.3 ALLOCATION OF DVAs AND LENGTH OF DISPOSITION PERIOD

Hydro Ottawa is requesting a one year rate rider for the proposed disposition period for the Group 1 and Group 2 (excluding LRAM) Accounts. Hydro Ottawa is also proposing to dispose of the LRAM rate rider over a one-year period in 2026 for all rate classes with the exception of General Service 50-1,499 kW. To help facilitate a more levelized rate impact between 2026-2027, Hydro Ottawa is proposing to dispose of the balance for the General Service 50-1,499 kW class over a one-year period in 2027.

Please refer to Tab “5. Allocation of balances" within Attachment 1-Staff-1(C) - OEB Workform - Deferral and Variance Account (Continuity Schedule) for the explanation of how the Group 1 and Group 2 rate riders were allocated.

As part of the 2024 Application, the following rate rider for the Street Light Class was approved to extend the disposition to a three-year period and the final year will occur in 2026:

- Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery.

10.4 BILLING DETERMINANTS

Hydro Ottawa has used the 2026 revenue load forecast billing determinants, as presented in Schedule 3-1-1 - Revenue Load and Customer Forecast, for the calculation of the rate riders. Hydro Ottawa has updated the percentages to allocate kWh and kW for Non-Regulated Price Plan (RPP) customers based on 2024 actuals. The Non-RPP percentage was then applied to the 2026 Load Forecast billing determinants. Wholesale Market Participants’ consumption was determined by using 2024 amounts as reported through RRRs.

10.5 CONTINUED, PROPOSED AMENDMENTS & NEWLY PROPOSED RATE RIDERS

10.5.1 Continued Rate Riders

Table AP below provides the approved Lost Revenue Adjustment Mechanism (LRAM) rate rider for the Street Light class that continues through 2026 as part of the 2024 Decision and Order.[26]

[26] Ontario Energy Board, *Decision and Rate Order*, EB-2023-0032 (December 14, 2021), pages 18-19.

Table AP - Approved Rate Rider for Account 1568 Year 3

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	# of Customers	-	$ -	**0.0000**	$
General Service < 50 kW	kWh	-	$ -	**0.0000**	$/kWh
General Service 50 to 1,499 kW	kW	-	$ -	**0.0000**	$/kWh
General Service 1,500 to 4,999 kW	kW	-	$ -	**0.0000**	$/kWh
Large Use	kW	-	$ -	**0.0000**	$/kWh
Unmetered Scattered Load	kWh	-	$ -	**0.0000**	$/kWh
Sentinel Lighting	kWh	-	$ -	**0.0000**	$/kWh
Street Lighting	kW	63,940	$ 312,830	**4.8925**	$/kW
TOTAL			**$ 312,830**		

10.5.2 Updated Proposed Rate Riders

Tables AQ through AW below outline the updated proposed rate riders to clear the DVA balances as at December 31, 2024 in the Group 1 and Group 2 Accounts for which Hydro Ottawa is seeking disposition. The original presentation of the Group 2 Accounts for proposed disposition can be found in Section 6 of Schedule 9-3-1 - Disposition of Deferral and Variance Accounts.

Table AQ - Proposed Rate Riders for Group 1 Accounts, excluding Global Adjustment (2026)[27]

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	kWh	2,601,493,648	$(1,254,284)	(0.0005)	$/kWh
General Service < 50 kW	kWh	722,555,976	$(289,206)	(0.0004)	$/kWh
General Service 50 to 1,499 kW	kW	6,987,734	$50,414	0.0072	$/kW
General Service 1,500 to 4,999 kW	kW	1,518,409	$(263,058)	(0.1732)	$/kW
Large Use	kW	1,015,559	$(196,003)	(0.1930)	$/kW
Unmetered Scattered Load	kWh	14,391,506	$(4,719)	(0.0003)	$/kWh
Sentinel Lighting	kW	120	$(13)	(0.1110)	$/kW
Street Lighting	kW	61,129	$(10,710)	(0.1752)	$/kW
TOTAL			**$(1,967,578)**		

Table AR – Proposed Rate Riders for Group 1 Accounts 1580 & 1588 - Non-WMP (2026)

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	kWh	2,601,493,648	$0	0	$/kWh
General Service < 50 kW	kWh	722,555,976	$0	0	$/kWh
General Service 50 to 1,499 kW	kW	6,927,905	$(1,158,636)	(0.1672)	$/kW
General Service 1,500 to 4,999 kW	kW	1,518,409	$0	$0	$/kW
Large Use	kW	1,015,559	$0	0	$/kW
Unmetered Scattered Load	kWh	14,391,506	$0	0	$/kWh
Sentinel Lighting	kW	40,631	$0	0	$/kW
Street Lighting	kW	21,961,791	$0	0	$/kW
TOTAL			**$(1,158,636)**		

[27] Totals may not sum due to rounding.

Table AS – Proposed Rate Riders for Account 1580 - Sub Account CBR Class B (2026)[28]

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	kWh	2,601,493,648	$ 1,132,797	0.0004	$/kWh
General Service < 50 kW	kWh	722,555,976	$ 314,630	0.0004	$/kWh
General Service 50 to 1,499 kW	kWh	2,343,906,694	$ 1,020,633	0.0004	$/kWh
General Service 1,500 to 4,999 kW	kWh	56,945,166	$ 24,796	0.0004	$/kWh
Large Use	kWh	90,765,888	$ 39,523	0.0004	$/kWh
Unmetered Scattered Load	kWh	14,391,506	$ 6,267	0.0004	$/kWh
Sentinel Lighting	kWh	40,631	$ 18	0.0004	$/kWh
Street Lighting	kWh	21,961,791	$ 9,563	0.0004	$/kWh
TOTAL			**$ 2,548,227**		

Table AT - Proposed Rate Rider for Account 1589 - Global Adjustment (2026)

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	kWh	20,825,400	$ 94,845	0.0046	$/kWh
General Service < 50 kW	kWh	100,201,626	$ 456,348	0.0046	$/kWh
General Service 50 to 1,499 kW	kWh	2,020,820,184	$ 9,203,416	0.0046	$/kWh
General Service 1,500 to 4,999 kW	kWh	56,945,166	$ 259,345	0.0046	$/kWh
Large Use	kWh	90,765,888	$ 413,375	0.0046	$/kWh
Unmetered Scattered Load	kWh	0	$ -	0.0000	$/kWh
Sentinel Lighting	kWh	0	$ -	0.0000	$/kWh
Street Lighting	kWh	21,961,791	$ 100,021	0.0046	$/kW
TOTAL			**$ 10,527,350**		

[28] Totals may not sum due to rounding.

Table AU - Updated Rate Riders for Group 2 Accounts (2026)[29]

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	# of Customers	348,287	$ (2,256,700)	(0.54)	$
General Service < 50 kW	kWh	722,555,976	$ (460,445)	(0.0006)	$/kWh
General Service 50 to 1,499 kW	kW	6,987,734	$ (840,548)	(0.1203)	$/kW
General Service 1,500 to 4,999 kW	kW	1,518,409	$ (200,113)	(0.1318)	$/kW
Large Use	kW	1,015,559	$ (130,963)	(0.1290)	$/kW
Unmetered Scattered Load	kWh	14,391,506	$ (12,836)	(0.0009)	$/kWh
Sentinel Lighting	kW	120	$ (115)	(0.9569)	$/kW
Street Lighting	kW	61,129	$ (20,531)	(0.3359)	$/kW
TOTAL			**$ (3,922,251)**		

Table AV - Updated Rate Riders for Accounts 1568 (2026)[30]

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	# of Customers	348,287	-	-	$
General Service < 50 kW	kWh	722,555,976	$ 267,165	0.0004	$/kWh
General Service 50 to 1,499 kW					
General Service 1,500 to 4,999 kW	kW	1,518,409	$ (620,234)	(0.4085)	$/kW
Large Use	kW	1,015,559	$ (491,433)	(0.4839)	$/kW
Unmetered Scattered Load	kWh	14,391,506	$ (7,215)	(0.0005)	$/kWh
Sentinel Lighting	kW	120	-	-	$/kW
Street Lighting	kW	61,129	$ (36,914)	(0.6039)	$/kW
TOTAL			**$ (888,630)**		

[29] Totals may not sum due to rounding.
[30] Totals may not sum due to rounding.

Table AW - Updated Rate Riders for Accounts 1568 (2027)[31]

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Rate Rider	Billing Determinant
Residential	# of Customers	-	$ -	-	$
General Service < 50 kW	kWh	-	$ -	-	$/kWh
General Service 50 to 1,499 kW	kW	6,987,734	$ 206,468	0.0295	$/kW
General Service 1,500 to 4,999 kW	kW	-	$ -	-	$/kW
Large Use	kW		$ -	-	$/kW
Unmetered Scattered Load	kWh		$ -	-	$/kWh
Sentinel Lighting	kW		$ -	-	$/kW
Street Lighting	kW		$ -	-	$/kW
TOTAL			**$ 206,468**		

10.6 GA AND WHOLESALE MARKET SERVICE CAPACITY BASED RECOVERY ("CBR") CLASS A ADJUSTMENT

In order to capture customer-specific impacts of transitioning Class A customers, Hydro Ottawa has provided customer level consumption in Attachment 1-Staff-1(C) - OEB Workform - Deferral and Variance Account (Continuity Schedule). The total amount allocated to Class A transitioning customers for GA is a debit of $312,079 and for CBR is a debit of $75,541. The monthly equal payment column has been grayed out in tab '6.1a GA Allocation' and '6.2a CBR B_Allocation' in Attachment 1-Staff-1(C) - OEB Workform - Deferral and Variance Account (Continuity Schedule), as Hydro Ottawa proposes to apply the customer-specific Class A GA adjustments and WMS CBR as a one-time adjustment rather than monthly. Unlike the use of rate riders, these adjustments are a manual process for Hydro Ottawa.

[31] Totals may not sum due to rounding.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-2

EVIDENCE REFERENCE:

Letters of Comment

QUESTION(S):

Following publication of the Notice of Application, the OEB received more than 140 letters of comment. Section 2.1.5 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent letters of comment are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

RESPONSE(S):

Hydro Ottawa has reviewed more than 140 letters of comment submitted to the OEB regarding Hydro Ottawa's EB-2024-0115 application and has organized its responses into key themes. See below for the main themes identified and Hydro Ottawa's response to the matters raised.

1. Affordability

Customer concerns: Customers expressed concern regarding the proposed rate increase's impact on affordability, particularly given the rising cost of living, inflation and financial strain on households, small businesses, and vulnerable groups.

Hydro Ottawa Response: Hydro Ottawa recognizes that rising living costs, inflation, and other financial pressures are making it harder for many customers—particularly households, small businesses, and vulnerable groups—to manage expenses. In developing its 2026–2030 plan, the utility has focused on balancing the need for critical system investments with the goal of minimizing rate impacts wherever possible.

The plan prioritizes essential work such as replacing aging infrastructure, meeting growing demand from electrification, and strengthening the grid against severe weather. By pacing these investments strategically over the five-year period, Hydro Ottawa aims to smooth out costs and avoid sudden, steep increases to customer bills.

Customer feedback has been an important part of this process. Engagement results show that 78% of residential customers who qualify for the Low-Income Energy Assistance Program (LEAP), and 85% of customers with an income below $71,000 (not LEAP-qualified), have indicated support for moving forward with the draft plan. Please see Attachment 1-4-2 (A), page 17 to Schedule 1-4-2 - Customer Engagement on the 2026-2030 Application.

Hydro Ottawa remains committed to managing costs responsibly and ensuring that every investment delivers clear value to customers in the form of safety, reliability, and long-term affordability. In addition, Hydro Ottawa fosters innovation and continuous improvement across its operations in order to manage costs.

2. Transparency of proposed increases

Customer concerns: Some customers found the filed rate application vague, technical, or lacking clear explanations for the necessity of increases, the use of funds, and benefits to customers.

Hydro Ottawa response:
Hydro Ottawa is committed to ensuring customers have clear, accessible information about its 2026–2030 rate application, including why increases are proposed, how funds will be used, and the benefits customers will receive.

All details of the plan—including evidence, data, and correspondence—are filed with the Ontario Energy Board (OEB) and posted on both the OEB's dedicated webpage for the application and Hydro Ottawa's "Active Applications" page. These public resources allow anyone to review the same information being considered by the regulator. As required, Hydro Ottawa also issued a formal "Notice of Hearing" to inform customers of the proposed changes and how they can participate in the review process.

Before filing, Hydro Ottawa conducted a proactive public engagement campaign using emails, social media, bill inserts, advertising, and a dedicated website. This campaign included clear explanations, diagrams, and plain-language summaries to help customers understand the plan, its impacts on the grid, and expected bill changes. Customers were invited to share their views through a detailed survey, and feedback was incorporated into the final application.

Through these efforts, Hydro Ottawa has aimed to make the process as open and transparent as possible, ensuring customers have the information and opportunity to be part of the conversation. As discussed in response to 1-CCC-10 the notice process provided customers a link to above-mentioned information, however it is unknown when reading some letters of comments whether respondents were able to review the full rate application linked. In addition, if customers were able to access the information, the scale of information may have been overwhelming or they may have found it difficult to find the elements important to them. This was a different approach from Hydro Ottawa's customer engagement "workbook survey" in which the distributor focused on

presenting the summarized information regarding the necessity of investments for system sustainability and future readiness, and the impacts of the proposed rate increase.

3. Service quality, reliability, and outages

Customer concerns: Some commenters raised issues about the frequency of power outages and declining service quality.

Hydro Ottawa response:

Reliability is a top priority for Hydro Ottawa. Customers rely on a dependable power supply for their homes, businesses, and essential services, and Hydro Ottawa is committed to maintaining and improving that reliability in the face of aging infrastructure, rapid growth, and more frequent severe weather events.

The 2026–2030 investment plan takes a targeted, data-driven approach to ensure service quality and reduce outage frequency. Key measures as part of the application include:

- Proactive replacement of aging equipment to prevent failures, gather better information to prioritize those investments and extend the life of critical assets where possible.
- Weather-hardening investments such as stronger poles, undergrounding in strategic locations, and improved storm response capabilities to protect against increasingly severe weather.
- Modernization of grid technology, including smart meters and advanced substation controls, to detect and respond to issues faster.
- Capacity upgrades to serve a growing community without compromising reliability.
- Better outage communications so customers receive timely, accurate updates when power is interrupted.

When looking at measures exclude interruptions caused by Major Event Days (MEDs) or Loss of Supply (LOS) from the provincial grid, Hydro Ottawa's 2023 Electricity Distributor Scorecard, between 2019 and 2023 shows an Average Interruption Frequency Index (SAIFI) has declined from 0.75 to 0.63, indicating that customers are experiencing fewer outages on average. While the

System Average Interruption Duration Index (SAIDI) has varied slightly year to year - reflecting the impact of severe weather events and other external factors - it has remained relatively stable and consistently within a narrow range, demonstrating that outage durations are being effectively managed. These measures exclude interruptions caused by Major Event Days (MEDs) or Loss of Supply (LOS) from the provincial grid.

Hydro Ottawa has become the “weather-alert capital of Canada,” facing a growing frequency and intensity of severe weather events. Notable recent weather events include the 2022 Derecho, the April 2023 ice storm, and multiple tornadoes, hail and record lightning strikes in summer 2023. SAIDI including all interruptions in 2019 was 1.30 while in 2023 was 6.92. SAIFI including all interruptions in 2019 was 1.08 and in 2023 1.48. In response, Hydro Ottawa is proposing investments in strategic distribution system resilience measures, such as feeder undergrounding of vulnerable overhead sections, line reinforcement, feeder reconfiguration, station egress undergrounding, and line relocations to better withstand future severe weather events and improve long-term reliability for customers.

Through these initiatives, Hydro Ottawa aims to not only maintain but enhance reliability, ensuring that customers have the safe, consistent service they expect - today and in the years ahead.

4. Hydro Ottawa's financial management and profitability

Customer concerns: Some customers proposed that Hydro Ottawa should leverage internal efficiencies, profits, or reserves to cover costs rather than increasing rates, citing reported profits and dividends paid to the City of Ottawa, and high executive salaries.

Hydro Ottawa response:

Hydro Ottawa operates within a complex landscape characterized by heightened customer sensitivity to electricity costs, persistent inflationary pressures, elevated interest rates, and an increasing reliance on an uninterrupted power supply. The period from 2021-2025 was particularly challenging, marked by the COVID-19 pandemic, the highest inflation in 40 years, a weakened Canadian dollar, supply chain disruptions, and extreme weather events, including the devastating

May 2022 Derecho storm. Despite these pressures, Hydro Ottawa prioritized customer affordability by forgoing a Z-factor application that could have allowed recovery of approximately $8.7M in OM&A costs and depreciation associated with $15.1M in capital additions related to the Derecho. This decision reflects a deliberate commitment to supporting customers during difficult times.

As a municipally-owned utility, Hydro Ottawa's financial results, including dividends to the City of Ottawa, are publicly disclosed. The proposed rate increase is separate from general revenues and is specifically intended to fund direct investments in the electricity distribution system to ensure its ongoing reliability and capacity for future growth. Under the OEB's regulatory framework, distribution rates are set based on prudently incurred costs. The framework allows for a return on investments, however does not allow for reserve funds

5. Alternatives to rate increases and efficiency

Customer concerns: Some customers expressed interest in having Hydro Ottawa explore other methods to avoid or minimize rate increases, including non-wires solutions.

Hydro Ottawa response:

Before filing its application, Hydro Ottawa took significant steps to reduce planned costs while still making the essential investments needed to keep the electricity system safe, reliable and ready for future growth.

Initially, a review of system needs showed almost $2 billion in required capital investments over the next five years. Recognizing that this was too high for both customers and the utility, Hydro Ottawa reduced its plan by 40%—to $1.2 billion—by deferring or scaling back lower-priority projects. Operating costs (OM&A) were also reduced from the original plan by approximately $20 million, including a reduction in staff levels and further cost savings across all divisions, some of which are tied to efficiency savings.

Hydro Ottawa also built in protections to help keep rates as low as possible, such as:

- Including costs for confirmed large load projects, with a special account to track variances, including deferring the payment of costs of expected additional requests and implication of residential development cost shifting policies.
- Sharing extra earnings with customers faster if company performance exceeds targets.
- Providing customers with the benefit of forecasted large load and electrification growth now, while only requesting to capture unanticipated changes related with large load customer-driven timing and taking the risk of electrification growth not materializing.

In addition, Hydro Ottawa continuously seeks out ways to operate more efficiently and control costs. During the current 2021-2025 rate term, numerous productivity initiatives have been implemented - resulting in real savings for customers. For the 2026-2030 term, the utility is building on this progress by using new technologies, streamlining operations, and reducing costs wherever possible. Comprehensive details of these initiatives were filed with Hydro Ottawa's application as Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement.

6. Alignment with green initiatives and future energy needs

Customer concerns: Owners of MicroFIT solar systems expressed concern that proposed increases to distribution charges would negatively impact the profitability of their installations. Some customers emphasized aligning investments with energy transition and net-zero goals.

Hydro Ottawa response:

Hydro Ottawa acknowledges the importance of supporting customers' clean energy objectives while maintaining a reliable and resilient electricity grid. The utility's 2026-2030 investment plan is designed to prepare for a greener future while addressing community growth and enhancing climate resilience.

Hydro Ottawa is making targeted investments to enable the energy transition. These investments include expanding capacity to meet rising demand from electric vehicles, heat pumps, and other electrification trends; strengthening the system to better withstand extreme weather; and integrating more customer-driven renewable generation such as solar and battery storage.

Between 2026 and 2030, Hydro Ottawa plans to expand substation, transformer, and line capacity, add new transmission connections, and commission a new substation each year to meet increasing demand. The utility is modernizing the grid with advanced sensors, automation, and data analytics to improve reliability and efficiency. Hydro Ottawa is also advancing Distributed Energy Resources (DERs) and Non-Wire Solutions (NWSs) to manage peak demand in more sustainable ways.

In addition to infrastructure improvements, Hydro Ottawa is investing in a greener fleet, lower-impact materials, and digital solutions to enhance efficiency and reduce its environmental footprint. Customer engagement activities indicate strong support for this balanced approach—one that advances the community's clean energy transition while ensuring a safe, resilient, and future-ready electricity system.

In addition, Hydro Ottawa is proposing to:

- Remove the Net Meter distribution charge,
- Decrease the micro generation charge due to cost efficiencies,
- Increased the >10KW generations service charge mainly related to inflationary increases.
- Reduce the largest generation service change due to efficiencies related to the growth of generators in this category,
- To offer Residential Electrical Isolations/Re-energizations for electrical work at no charge to the customers.

7. Concerns over Notice of Hearing communications

Customer concerns: Concerns were raised regarding the lack of clarity and detail of the notice of hearing email, and the overwhelming volume of technical documents to review; suggestions were made for clearer, plain-language communication.

Hydro Ottawa response:

As Hydro Ottawa's regulator, the OEB mandates the specific format and content of these notices to ensure all affected customers are formally informed about the utility's rate application and customers' right to participate in the regulatory review. While this means the language can

sometimes be direct and legalistic to meet regulatory requirements, its sole purpose is to provide clear, mandated information about the public hearing process for our application. Hydro Ottawa is limited in the additional context it can include in these specific OEB-mandated communications.

Hydro Ottawa acknowledges that the formal nature of this notice may have caused confusion or concern for some customers. Customer feedback is invaluable, and the utility is committed to continuous improvement.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-3

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 1 / Schedule 1 / pp. 8-11 (pdf Exhibit 1 part 1, pp. 222-225)
Ref. 2: Exhibit 1 / Tab 3 / Schedule 4 / pp. 11, 23, 26 (pdf Exhibit 1 part 1, pp. 531, 543, 546,)

Preamble:
Table 1 - Hydro Ottawa's Current vs. Proposed Custom Rate Frameworks in reference 1 states that the 2026 Operating, Maintenance and Administration (OM&A) amount is "Standard Cost of Service rebasing with embedded stretch".

QUESTION(S):

a) Please add a column to each of Table 2, Table 4 and Table 5 in reference 2, and show the productivity benefits specific to 2026 for each row of OM&A expenses.
b) If the OM&A productivity benefits from question a) do not reconcile with the quote from reference 1, please explain and detail the additional items contributing to the embedded stretch.

RESPONSE(S):

a) Tables 2, 4, and 5 from Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement are shown below as Tables A, B, and C respectively, with productivity benefits specific to 2026 for OM&A. Table D summarizes the total OM&A expenses. Hydro Ottawa notes the productivity benefits in Table 5 in Schedule 1-3-4 are reflected in Table 4 in the initiative "3.2.2 Online Billing Enhancements". As such, the amounts from Table C are not explicitly added in the summary in Table D as to not double count the amounts already included from Table B.

Table A - Labour and Supply Chain Optimization Initiatives (Quantifiable)[1] ($'000s)

Initiative	Description	OM&A Productivity Benefits		
		2021-2025	2026-2030	2026
3.1.2 Fleet Pooling	Fleet pooling pilot program, allowing for more effective and extensive sharing of corporate vehicles by field crews, supervisors and administrative employees	n/a	$ 870	$ 122
3.1.3 Cable Locates Efficiency	Implemented automated clearing processes and Alternate Locate Agreements to reduce field visits	$ 2,425	$ 3,694	$ 662
Total OM&A		**$ 2,425**	**$ 4,564**	**$ 784**

[1] Totals may not sum due to rounding.

Table B - Innovation and Digital Transformation Initiatives (Quantifiable)[23] ($'000s)

Initiative	Description	OM&A Productivity Benefits		
		2021-2025	2026-2030	2026
3.2.1 Net Metering Automation	Streamlined net metering billing processes, saving significant labor hours per month.	n/a	$ 6,751	$ 241
3.2.2 Online Billing Enhancements	Expanded online billing, reducing mailing and printing costs (with ancillary savings related to Account Overdue Notices)	$ 6,394	$ 5,495	$ 524
3.2.3 Remote Disconnection Technology	Expanded use of remote disconnect meters, reducing labor costs for service terminations and reconnections.	$ 2,869	$ 4,941	$ 904
3.2.5 Disconnection Notification Automation	Replacement of manual delivery of disconnection notices with automated notifications	$ 1,849	$ 2,202	$ 410
3.2.6 Satellite Imaging for Vegetation Management	Used satellite data to identify high-risk vegetation areas and optimize trimming schedules.	n/a	$ 1,637	$ 178
3.2.8 Move-In Move-Out Automation	Automated customer move-in/move-out requests to reduce manual processing and errors.	$ 502	$ 923	$ 173
3.2.9 Salesforce Field Service for Reliability Operations	Centralized work requests and scheduling, reducing reliance on manual communication and increasing productivity.	$ 141	$ 769	$ 146
3.2.11 Customer Information System Reduced Fees	Reduced managed service costs	$ 480	n/a	n/a
Total OM&A		**$ 12,236**	**$ 22,717**	**$ 2,577**

[2] 3.2.2 Online Billing Enhancements was updated from the original amount filed in the initial rate application. For further details, please refer to interrogatory 1-SEC-27.
[3] Totals may not sum due to rounding.

Table C - Breakdown of Productivity Benefits for Online Billing and Account Overdue Notices ($'000 000s)[4]

	Historical / Bridge Years	Test Years	Test Year
	2021-2025	2026-2030	2026
Online Billing	$ 5.8	$ 4.2	$ 0.3
Account Overdue Notices (AON)	$ 0.6	$ 1.3	$ 0.2
TOTAL	**$ 6.4**	**$ 5.5**	**$ 0.5**

Table D - Summary of OM&A 2026 Quantifiable Productivity Benefits[5] ($'000s)

Category	2026 Productivity Benefit
Labour and Supply Chain Optimization	$784
Innovation and Digital Transformation	$2,577
TOTAL	**$ 3,360**

b) Hydro Ottawa notes that Ref.1 should read Exhibit 1 / Tab 3 / Schedule 1/ pp. 8-11.

The OM&A productivity benefits reconcile with the quote from reference 1. The 2026 OM&A rebasing amount of $140M was set with assumptions of embedded productivity of $3.4M corresponding to a reduction of 2.3%.

[4] 3.2.2 Online Billing Enhancements was updated from the original amount filed in the initial rate application. The amounts in the Account Overdue Notices (AON) row reflect these changes. For further details, please refer to interrogatory 1-SEC-27.
[5] 3.2.2 Online Billing Enhancements was updated from the original amount filed in the initial rate application. The amounts in the Innovation and Digital Transformation row reflect these changes. For further details, please refer to interrogatory 1-SEC-27.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-4

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 1 / Schedule 4 / pp. 6-12 (pdf Exhibit 1 part 1, pp. 54-60)
Ref. 2: EB-2019-0261, Decision and Order, November 19, 2020
Ref. 3: Hydro Ottawa CIR Year 2 Update, Exhibit 1 / Tab 1 / Schedule 6, p. 6
Ref. 4: 2023 Hydro Ottawa Rate Application, Exhibit 1 / Tab 1 / Schedule 6, p. 6
Ref. 5: 2024 Hydro Ottawa Rate Application, Exhibit 1 / Tab 1 / Schedule 6, p. 6
Ref. 6: HOL EB-2024-0032 Application, Exhibit 1 / Tab 1 / Schedule 6, p. 7

Preamble:
It its Decision and Order in EB-2019-0261, dated November 19, 2020, the OEB accepted the settlement proposal as filed. Page 23 of the settlement proposal included the understanding that Hydro Ottawa would report on the MiGen project in the next rebasing application.

The MiGen reporting was not listed in section 12, OEB Directives from Previous Decisions and/or Orders, of Exhibit 1, although it was included in Hydro Ottawa's past four annual updates under its five-year custom incentive rate-setting plan.

QUESTION(S):

a) Please provide the agreed to MiGen report as described in the settlement proposal.
b) Please confirm if the MiGen program is still underway.
    i) If yes, has the program been renamed and referenced as another initiative in the current 2026-2030 application?
    ii) If yes, does Hydro Ottawa anticipate the MiGen program to continue throughout the 2026-2030 period? If yes, is any funding being requested?
    iii) If no, when and why did Hydro Ottawa decide to end the MiGen program?

c) Were any learnings from the MiGen program leveraged in the design of the non-wires solutions (NWS) initiatives proposed in Hydro Ottawa's current application?

i) If yes, please identify for which NWS initiative(s) and provide more details as to how the learnings were leveraged in the NWS program design.

RESPONSE(S):

a) For clarity, the language in Hydro Ottawa's Final Settlement Proposal, dated September 17, 2020, states the following:

> *The Parties are generally supportive of Phase 1 of the MiGen pilot project of non-wires alternatives to reliability and bi-directional customer efficiency measures that have been undertaken at no cost to the utility and its customers. The Parties support Phase 2 of the MiGen pilot project (as described in the updates to section 2.3.3 of Attachment 2-4-3(E): Material Investments filed on May 5, 2020 and in the response to interrogatory DRC-9) on the understanding that (i) all parameters and metrics (including the project's impact on reliability, customer costs/savings, generation, electric vehicle penetration, line losses, and potential costs and savings from any proposed future expansion of the pilot after 2025) be reported and included in Hydro Ottawa's next rebasing application, and (ii) the ratepayer costs of the project be limited to the budgeted $2.2M over the 2021-2025 period.*

Within the application the EV Everywhere project was the outcome of the MiGen portfolio. Specifically, the funding that was initially provisioned for MiGen was used to support Hydro Ottawa's contributions towards the IESO GIF's EV Everywhere project. For further details on the EV Everywhere project, please refer to 2-Staff-68. For learnings associated with the NRCan funded Mi-Gen pilot project, please refer to Attachment 1-Staff-4(A) - Hydro Ottawa MiGen Ph II Closeout, for the lessons learned report that was submitted to NRCan as part of the project close-out.

b) The MiGen program is still underway

i) The program has not been renamed. As noted in a) above, the MiGen Program contains the EV Everywhere project

ii) Hydro Ottawa is contemplating the future use of the MiGen brand and, as a result, did not include the project name MiGen in the current application, which unfortunately left a disconnection to the Settlement obligation. Hydro Ottawa's proposed ODERA project is a natural progression of the EV Everywhere project and although not stipulated as MiGen in the 2026-2030 application, the program aligns with the core intent of the MiGen program and falls within this budget program during the 2025 term.

iii) See response (a) ii).

c) Yes

i) As noted on p.39 of Section 2.4.4 of Schedule 1-4-1 - Customer Engagement Ongoing, Hydro Ottawa has qualified the ODERA project as the "logical next step" following learnings from the EV Everywhere. For details on how the learnings from the EV Everywhere project and, by extension, the MiGen program informed Hydro Ottawa's NWS program design, please see 2-Staff-69 (e).

MiGen Ph II Closeout Summary Template

This document is written for NRCan's Smart Grid Program to satisfy program requirements. Confidential information is highlighted and must not be shared externally. Any subsequent knowledge products made for public distribution about this project by NRCan will be approved by Hydro Ottawa before release.

Program Intro

Problem

In Ontario, the amount of DERs that have been contracted or installed is growing. If not managed effectively this could affect the power grid system reliability and cost more for customers. There are lessons to be learned around customer experience and behaviour, micro transactions, security and privacy and electricity commerce in the future transactive energy grid. It is also important to explore affordable electrification pathways for low-income customers and owners of multi-residential buildings.

Project Design

The goal of the MiGen project was to simulate a platform that provides real time visibility into customer generation and consumption, and enable the utility to manage that energy at the edge of the distribution system - that's where what happens with electricity generation and use greatly snowballs to affect the grid buildout, grid integrity and cost of service. The project was designed to better understand the beneficial impact DER's at the grid edge can have atthe grid edge and on the entire grid, including the wholesale supply-demand balance. The Net-Zero Community MiGen use case demonstration for this project was to be accomplished at two affordable housing sites (Gloucester Community Housing Corp & Ottawa Community Housing Corp) to emphasize the need and potentiality for DER integration for low-income customers.

Pathways to Scale

There are multiple possible pathways to scale a project such as this one that is strongly influenced by a provincial regulation, which governs a monopoly utility's ability to engage on the behind-the-meter side of the solution. At the two extremes are a utility-centric approach, versus a market-centric approach, the latter being the MiGen vision. The utility-centric approach involves the utility acting as a service provider for customers for the bulk-purchasing,installation, care and management of behind-the-meter (BtM) DER related equipment (devices or systems) for customers. Whereas a market-centric approach, again per the MiGen vision, would see the utility facilitating the interconnection of BtM customer DER related equipment, however, private sector players would support all of the purchasing, installation and operation of customer DERs if the customer required it. The desire from MiGen was to stimulate a competitive market for BtM DER related equipment and services that function within a broadly adopted interoperable utility platform.

Acronyms

"AI" means artificial intelligence that is programmed into self-learning machines or devices.

"Back-Office-System" or BOS" means the hardware, firmware and software components, that: (a) are upstream of the TAs; (b) manage the TAs; (c) follow the data governance model (i.e., data capture, storage, and analysis); (d) present information to the user; and (e) issues master Demand Response

commands. It would include the APP the Customer would use to indirectly interface with the utility and the HEMS.

“Customer Agent” or “CA” means a stand-alone or integrated Project element that has the ability to understand the customer’s load needs and generation ability and can communicate and negotiate with or respond to a command from a Transformer Agent on behalf of the customer.

“Distributed Energy Resources” or “DERs” as defined by the Ontario IESO “are electricity-producing resources or controllable loads that are connected to a local distribution system or connected to a host facility within the local distribution system. DERs can include solar panels, combined heat and power plants, electricity storage, small natural gas-fuelled generators, electric vehicles and controllable loads, such as HVAC systems and electric water heaters.”

“Demand Response” or “DR” means a request by the market operator or the Proponent to reduce the load by, for example but not limited to, a thermostat setting change, a load control device turning off or curtailing load or by injecting energy into the grid, for the likely purpose of matching supply, remaining within asset electrical capacity, or reducing greenhouse gas burden.

“EVSE” means Electric Vehicle Supply Equipment, in reference to EV chargers.

“HEMS” means home energy management system.

“HEMS Controller” or “HEMSC” means the Project element that interfaces between the Customer Agent and HEMS. Its function is to translate between the Customer Agent protocol language and HEMS protocol language and collect certain data required by The GREAT-DR, but is not presently available through the HEMS Solutions.

“HEMS Solutions” means a consumer available technology product used to produce, store, or manage the use or provision of energy and includes load control modules, solar panels, inverters, batteries of 120V or more, battery management systems, in-home communication systems, thermostats for controlling heating/ventilating/air-conditioning, and meter data collectors.

“HVAC” means Heating Ventilating and Air Conditioning, in reference to the equipment needed for space climate conditioning.

“Local Distribution Company” or “LDC” refers to the electric distribution utility as structured in the province of Ontario, Canada.

“OEM” means original equipment manufacturer.

“Transactive Energy” means the energy resulting from the reduction in load or greenhouse gas burden which is then offered in exchange for a benefit.

“Transformer Agent” or “TA” means a stand-alone Project element which monitors neighbourhood transformer loading and health; negotiates with Customer Agents located in the transformer neighbourhood or other TAs; and communicates with the upstream local electricity distribution system on behalf of the transformer.

Phase II Pivot

Phase I of the project was funded by the Ontario Smart Grid Fund, and it successfully demonstrated MiGen's solution Platform's capability to enable negotiated Transactive Demand Response at the grid edge through a decentralized architecture. That architecture has since been adopted by Grid Wise, upholding three design principles: (1) privacy-by-design, (2) interoperability, and (3) best cybersecurity practices.

Phase II of the project, funded by the NRCan Smart Grid Program was intended to begin retrofitting the all-electric existing 38-unit Gloucester Housing Corporation (GHC) development with CA+HEMSC, solar PV, smart inverter, battery energy storage, thermal baseboards, air-source heat-pump with thermal storage, and HEMS (smart thermostat, load controllers). In addition, Hydro Ottawa planned to engage with a third-party service provider who wouldt build a cloud-based platform that broadcasts the following data for residential customers:

- new buy and sell energy rate structure signals,
- GHG signals that represent the real-time provincial generation carbon footprint, and
- significant event alerts to inform customers of important information that will impact their service.

However, Phase I was not completed before the Phase II proposal was submitted under NRCan's funding program call. This led to the Phase II application being based on the assumption of certain Phase I outcomes which didn't materialize. The technical solution was proven to work, however, business, regulatory and project management concerns demised the project. Thus, Hydro Ottawa attempted to pivot the approach while remaining consistent with overall project objectives at the beginning of Phase II for a number of reasons. Of note, three lessons are listed and are elaborated on further:

- Unclear financial benefit to the utility.
- Unclear pathway to scale should the project be successful. Challenges managing across the dozen or so partners in the project. The Phase II project was a systems design, build, test and deploy. Each partner had their own challenges and with the limited time and resources, pressures grew to de-risk by de-scoping.
- Unclear or non-committed regulator or market authority support. The project challenged the electricity market and utility business model norm, and time to gain authority interest and support ran out.

<u>Unclear financial benefit to the utility</u>

Present Ontario electricity regulation favours capital investments over operating expenses. The cost of capital investments is recovered over the asset's life and thus has a minimal effect on customer rates, whereas operating expenses are recovered annually and thus can have a greater, more immediate rise in customer rates. Non-Wires Alternative (NWA) solutions, like MiGen, are more technology based over standard infrastructure build, and thus may be lower in overall cost, though higher in ongoing operating costs. Thus, decisions to overburden an asset, like a distribution transformer, to failure and replace it with another asset may be more financially prudent than to manage the burden on the asset. However, whether just more capital investment would be sufficient in mitigating load growth, higher penetration of DERs and logistical concerns for accommodating growing electrification was, at the time, not well understood to be at the forefront of thought.

Unclear pathways to scale

Uncertainty about the industry regulatory environment meant that the estimated $10-15 million needed to commercialize the project after Phase II may have been challenging to gain; the utility's investment in creating the Open Source platform for wider industry benefit would need to be regained. This and the following issues challenged scaling:

1) Hydro Ottawa lacked experience to guide the commercialization of an open source world-wide royalty free product and thus it was a challenge to enable developing spin-off opportunities.
2) Scope reduction changed the team dynamics, and to be more competitive rather than collaborative.
3) The business model of accessing vendor APIs for leading thermostat OEMS changed during the project requiring changes or re-development.. t .

However, two developments that did help scaling was the IEEE 2030.5-2018 Interoperability standard, and international interest in MiGen. This standard was critical to our project and we adapted it for real field deployment. HOL's and uO's work with the IEEE Standards Association US Dept. of Energy sponsored roadmapping and IEEE's conformity procedures for IEEE 2030.5 helped solidify MiGen's requirements from this standard as being a solid standard - not guideline, or pick-and-chose - for long term use. However, the first generation coding for the MiGen platform would need modification to conform. Our efforts helped improve this interoperability standard, make it backwards compatible moving forward, and non-threatening (potentially symbiotic) to other standards owners for i.e., SunSpec and OpenADR, and more cyber-secure. In meetings with SunSpec and OpenADR owners during roadmapping exercises, MiGen made it evident how this interoperability standard helps bridge between behind-the-meter protocols like theirs and the utility protocols like DNP3 and IEC61850. Also, much interest in MiGen was gained from utilities, media and OEMs stemming from our and our partners' attending trade shows, fielding trade media interviews, plus presenting about MiGen and in informal meetings with some consumer technology OEMs.

Challenges managing many project partners

In total the project included 15 partners:

- four (4) product vendors: two solarPV smart inverter types (central & micro-string), a battery energy storage system, smart thermostat and load controller, and one air-source heat-pump with thermal storage;
- one (1) assembler and tester;
- one (1) installer & field service provider;
- one (1) engineering support;
- eight (8) developers: one for the core platform, one for the communications and security, one for one for transactive energy connection; one for prosumer response & behaviour intelligence plus transaction ledger & settlement; one for prosumer APP; one for prosumer voice query & command feature; two for grid intelligence - in-front-of-meter, and behind-the-meter assets.

The critical path was the core platform, and everything else could have been emulated. However, everything else was to bolster the practical viability: prove in-field the practical Net-Zero Communities use case; spark the ecosystem for the platform and establish commercial partnerships for scaling. Hydro

Ottawa became challenged with time, money and people to manage the developers' deliverables. When de-scoping to manage with these constraints, it became difficult to maintain relations with partners especially as time passed while Hydro Ottawa was deciding on its final project commitments. SMEs with academic partners had difficulty adapting to the changing workload due to the semester structure of post-secondary institutions, and commercial partners had to refocus on survival as their markets in Ontario and the US became more uncertain between the time of application and project start. To make matters even more challenging, staff at Hydro Ottawa faced resource constraints during the project launch period, diverting the focus from the MiGen project to other priorities.

Unclear or non-committed regulator or market authority support

Use of DERs in a Transactive Energy Market as a Non-Wires Alternative solution to help the wholesale supply-demand balance plus the local and hyper-local distribution grid is not a new concept to North America, though its practice beyond few and far-between trials in the US and familiarity in Canada was very limited. The two regulated markets in Canada are Alberta and Ontario, and only Ontario was trialing beyond the energy market into the ancillary market. These trials were specifically for DERs greater than 1MW and were intended to only uphold the integrity of the wholesale grid, not the transmission or distribution grids. Politically, and thus legislatively, the Ministry of Energy, the IESO nor the OEB were prepared enough to provide committed support for a local distribution utility's DER Transactive Energy trial that would challenge processes, rules and regulation at the time. However, thankfully, interest, capacity and sandbox mechanisms are now available in 2022.

What can other Smart Grid Program recipients learn from this project?

Impacts of funding timelines on project launch

Securing project financing from NRCan's Smart Grid Program and uncertainties on the timeline led to difficulties in recruiting and retaining talent on the project, particularly for academic partners and Hydro Ottawa. The funding timeline affected each project participant sector as follows:

- Academic Partners: delays led to issues in retaining subject matter experts (SMEs), as it became difficult to manage grants for ancillary research projects that support development and deployment to make sure they aligned well with the core project timing.
- Site Hosts: The same funding issues affected work with the affordable housing partner creating uncertainty about scalability for Phase II.
- Developers & Commercial: partners had business plans that were stressed by a near two-year wait from project proposal to project launch.
- Installer: uncertainty in the renewable generation and electrification marketplace created uncertainty in retention of their skilled workers and their viability.
- Proponent: Hydro Ottawa had reduced its staff capacity on the project to focus on more immediate business concerns.

Considerations for mitigation measures: Ideally, all the partners would have been kept, their deliverable end-uses prioritized to keep the vendor partner engaged to maintain project credibility, and to facilitate earlier commercialization. However, mitigation measures considered were, in no particular order:

1) Hydro Ottawa, at any time pre-project or during the project, could have mitigated the impact of a delayed launch on the partners or their failure to deliver by using an emulation file to prove vendor plug-in capability.
2) A few or all partners could have become just advisors, or in the extreme could have been dropped from participation.
3) Partner end-use cases could have been prioritized to a shorter list with the balance satisfied through emulation.

Note that contemplation of mitigating measures had not influenced the need for a project pivot (as discussed later), from the core project concept and desired outcome. Thus, the timing delay between project application and approval did strain the project team before the Phase II project officially began, and that also affected the ability to manage the subsequent changes.

> **Recommendation:** NRCan should ensure that the time from the submission of a project proposal to the completion of due diligence and funding agreement signing is one year or less. A process that's longer introduces risks to retaining partners and internal commitment. For example, our academic partners, some SMEs found employment.

For NRCan: Further background on the effect of timeline and program commitment comes from the Phase I project. Phase I of this project, which was funded separately by a different program, experienced many delays that resulted in the two project phases overlapping. The proposal submission deadline for Phase I was Nov. 30/'15, and the contract was signed in Mar./'17 with an effective date in Apr./'16; only foundational administrative and project planning work was done in between. After the official project start, - a year until the contract was signed, public uncertainty with provincial direction with electricity rates and support for renewable generation programs dampened customer recruitment success. Also, project momentum was difficult to retain during and after the provincial election given uncertainty over continuation of the Phase I funding.

Managing projects with many partners

A large number of partners were brought in on this project, providing hardware, firmware and software, vendor products, and design support. Plus, there was the needed communications with Phase I participants, the community affordable housing corporations, and engineering consultants as they were to become involved in Phase II too. The organization of these partners and maintaining an efficient communication network provided an extra challenge for the project.

Three issues arose concerning the many partners we had. Details follow, however, in brief they are: (1) resourcing - project timing affected: scope, HOL plus partner available resources, team dynamics from competing to remain on the project as HOL re-scoped;

(2) partner engagement - the number of partners, their timelines, inter-communications, project proponent's treatment of partners as partners or just as providers of service; and pre-payment issues;

(3) product interfacing - choices / availability of products, potential complexity to manage.

Resourcing

As time passed, particularly post contract awarding while Hydro Ottawa was actively descoping, a few dynamics happened: (i) Hydro Ottawa resources became more diverted to core business and partners

were advised to pause work; (ii) partners either redirected their resources to other projects while waiting for their re-involvement or, specifically the academic partners, continued to work despite the pause to keep their resources from seeking other employment and to prevent delivery failure on the original critical path tasks, assuming scope change for these tasks wouldn't be an issue. With partner investment in the outcome of the MiGen Ph II project, when the intent to descope was communicated, some partners expressed reasons for their continued involvement and ideas for a descoped project. In the end, the proposed new scope was a complete project pivot that would be to trial voluntary customer load curtailment based on a proposed new rate structure and signals.

Partner Engagement

The MiGen project was structured to rely on influencing partners to help develop an energy industry transformative open source platform, and conversely to rely on these partners for adopting this platform as the pioneers and help build the sustaining ecosystem of users and providers. Communication between the project parties and involvement in the platform's design was to be important. Unfortunately, the role of a "Partner" became confused between being just a service or product provider, and being that party with whom the Proponent communicated with on all project aspects and engaged with in decision making, though the final decision may be the Proponent's. The minimal and uni-directional communication and involvement of the partners during the descoping/pivoting process created uncertainty amongst the partners and led to some friction between all parties.

From the project proposal creation to the project kick-off, the partners were engaged in forming and aligned to the Proponent's MiGen goals, objectives and project plan. To kick-start the project and regain lost time, equipment from vendors was purchased and received, and other partners were pre-paid a proportional amount to cover early critical path milestone objectives. This led to challenges when the project began pivoting direction. Hydro Ottawa asked non-vendor partners to pause work on the project while the technical and business model direction was being reconsidered. Already, much of the project planning, including design and preparation for the first field installation site had been undertaken by that point. Also, some of the partners continued their work on critical path items despite the pause period unaware that descoping became a complete pivot.

> Recommendation: Hydro Ottawa recommends good communications and involvement of project partners and caution when pre-paying vendors in case of project delays, project cancellation, scope change or project pivoting.

A separate communication matter related to the project prosumer participants. Due to the work with a housing community, the communication trail with participants was longer than for other projects. This led to increased risk, and the realization of communication issues where the participants were not properly informed of site visits, creating, though very few, frustrations for all parties.

> Recommendation: Special attention should be paid, especially when working with long communication chains, to ensure all parties are kept up-to-date on activities.

Product Interfacing

One objective of MiGen Ph II was to trial as many interfacing products related to achievement of Net-Zero through electrification. We succeeded in gaining two different form (micro-string and central type without battery storage coordination and with, respectively) solarPV smart inverter OEMs, a cold climate

Air-Source Heat Pump (ASHP) OEM, and voice activation developer for easier prosumer interface with the systems and platform. However, other than the smart thermostat developed by the ASHP OEM, serious challenges were faced with growing the number of smart thermostats with which MiGen could interface for this project. Tantalus was dropping their line of smart thermostats given the gorillas in the market, the gorillas - Amazon and Google - had decided to change the terms of engagement with developers and interfacers that would make it bureaucratic, consistent or dependable management uncertain - because of rules on who may have access, the number of DR events allowed, and other changeable rules of engagement - and definitely uneconomic - because of the access fees per thermostat - for this project. Post project, it may have been possible to either convince these OEMs to naturally make their thermostats be interoperable with MiGen, or, because of the open-source interoperable MiGen platform, create an encouraging opportunity for new market entrants, like MiGen was doing for the ASHP OEM.

Technical Issues and Discoveries Encountered

The goals for the MiGen platform's development were to be open-source and world-wide royalty free for broad adoption, decentralized for robustness, and prosumer-grid-market tri-centric for grid democratization, competition and development of sustaining beneficial behaviours. Generally, the technical aspects of the MiGen platform were successfully achieved in Phase I; we successfully tested the DR and TEM use cases successfully in the field. Thus, proven was the efficacy of a decentralized software agent based DR and Transactive Energy platform design premised by three pillars: interoperable, privacy-by-design, and best cyber-security principles. However, the following three issues and discoveries are detailed:

(1) Field Area Network (FAN) communication between devices will always be a challenge;

(2) Compensation for incenting DR participation is not as trivial as widely thought;

(3) Distribution transformer health assessment methods need more thought.

FAN Communications

A robust communications infrastructure is critical to a utility's dependability on Demand Response as a Non-Wires Alternative solution, and its affordability is critical to the cost effectiveness of a grid-edge platform with several interdependent devices that also are remote to each other. Thus, a pursuit was to create an open-source, low cost, grid-edge Field Area Network solution by means of an open-source, low power, off-the-shelf component Wi-Fi Mesh between the CAs and associated TA.

In the lab environment and sanitary field deployment, the Wi-Fi Mesh developed worked well. However, in the real implementation environment, difficulties arose that were challenging to resolve satisfactorily given the nearing-end of Phase I. The four main issues encountered, and listed below, compounded with each other led to messaging delays at best and message drops at worst:

1) Hardware - the CA and TA computing hardware used was the RaspberryPi3B, and an inherent constraint was the single controller that had to be priority shared with the communication system requirements.
2) Mesh Protocol - there are different open-source mesh protocols for routing messages among devices towards the ultimate destination, and each has its trade-offs. Time was lacking for investigating these options in Phase I.

3) Topology - a mesh network works best with a star (spoke and hub) type topology. However, the trial deployment in Ph. I was linear; the CA just before the TA had to buffer the communications for all the downstream CAs.

A concern with any communication set-up is the need to tune to avoid interference and position antennas to clear signal blocking elements in the environment; many FAN solutions exist, but all will need regular management For mesh networks, the latter can be overcome with more communication nodes within the mesh, however, interference would remain a matter to monitor and tune away from in absence of a dedicated frequency spectrum. Another concern with communications systems is the need for power for the devices, and with the devices we used, Ethernet power for the CAs that contained the communication system would have sufficed. These issues noted would have been of concern to resolve in Ph II, and necessary to have been resolved for the future releases. Of note is that MiGen did not and does not need to mandate the communications technology to be used between the TA and CAs; MiGen is agnostic to the FAN or any other utility communication system desired.

> **Recommendation for Proponents:** A “fail forward” culture to project outcome is important, especially for transformative projects. The Proponent should have an understanding that what is developed as a prototype i.e., pre-commercialization, is a throw away development and for commercialization is replaced by a permanent build that is current to updated standards and to commercialization quality.

Compensating DR Participation

A common thought in the DR world is that DR would create a valuable monetary source of compensation for the prosumer and service providers. A valuable lessons from Ph I was that: (1) the monetary value of DR small scale activity is yet to be quantified; (2) the measurement and validation of small scale device contribution resulting from a DR call using the premise revenue meter is very challenging and will continue to be a challenge for any DR compensation program; (3) prosumer incentive to participate in DR calls should consider the manageable device activity, and not just what is measured at the revenue meter. At the grid-edge i.e., within a prosumer’s premise, the load and energy source states are volatile and difficult to consistently notice the cause-and-effect of a DR call because of the behaviour of the other unpredictable and non-managed or monitored device. . This, in turn, would make it difficult to properly compensate the participants based alone on dollars per kW reduced. In Ph II, proposed was a prosumer behaviour AI system to assess the likelihood of a response to an upcoming DR signal with a participation incentive and the likely resulting effect so that confidence in a DR outcome can be depended upon. Input from the CA that monitors device commitment and response to validate DR participation would be used for settlement purposes, and for informing future behaviour predictions.

> **Recommendation:** Technical solutions should continue to be developed to more economically measure and validate DR contribution, however regulation will be needed to ensure fairness, transparency and consistency in this matter. Cost and space considerations aside, the most effective devices to manage BtM are energy storage devices (more so batteries), and large flexible loads like electric water heating, HVAC fans/blowers/pumps, and EVSEs.. This is because they are large enough to influence the load profile, have the most flexibility in terms of timing plus duration, and can have no comfort impact to the participant if managed well. Smart thermostats are least favoured; though they can only shave load, it is only in certain seasons, they may only have relatively small impacts on load shedding (most reputable studies say by 2%) for the

present access fees to OEMs ($25-$100 per year per thermostat), and they are more likely to impact participant comfort.

Distribution Transformer Health Monitoring

Knowledge of an asset's "dynamic rating" is key to optimizing its utilization. An asset's nominal rating is the conservative loading it can handle to maintain an adequate lab reference operating temperature so it can last for its expected operating life; the hotter a transformer operates beyond a threshold for a longer time, its chance of failure escalates. However, loading can be higher than nominal if the operating temperature is managed based on factors such as ambient climate and duration of high loading. This variable loading capacity is called an asset's "Dynamic rating." Thus an asset can be loaded above nominal rating to avoid early upgrade if the dynamic rating is known. In Phase I, to determine the distribution transformer's dynamic rating, a temperature sensor was placed on the outside shell of the transformer just below the oil level and another placed outside to measure ambient temperature. Power sensors were also added to the secondary and primary sides of the transformer. Ideally, the temperature sensor would have been placed inside the transformer, right in the middle of the core where the hottest temperature is typically expected. The power sensors also provided visibility to the amperage and voltage changes in response to a DR call. This information was then used to calculate the dynamic rating. Lessons learned were:

1) The temperature sensor on the transformer shell was not a good representation of the transformer's internal thermal temperature.
2) The cost of external sensors may be significantly reduced if purchased embedded within the transformer, and the added benefit would be that actual core temperature can be measured.
3) Proxies for the measured core temperature may be less costly and be good enough. If a utility could continuously aggregate customer revenue meter readings, use publicly available general city ambient temperature and wind speed, then the core temperature may be reasonably estimated. The overall cost-benefit of the decentralized hardware sensor and software solution, versus a centralized monitoring and software solution would be interesting to assess.

   Recommendation: methods to simulate the health and monitor virtually may have lower cost to benefit merits and should be further explored.

Policy Issues Encountered

The changing policy environment adds complexity to solution design in ways both technical and business model related. As mentioned above, Phase I experienced large delays. At the time of the project, the provincial government's changes to the sector and promise of lower electricity prices caused some delays and affected the vendor and service provider partner viability in the renewables space. There is no real recommendation proposed here, except perhaps to try to evaluate a project's sensitivity to some of these possible political changes.

Market Issues Encountered

Hydro Ottawa's original approach was to develop a solution suitable for its customers and to find a private sector partner to commercialize that solution. Though academic partners on the project can support up to trialing of pre-commercialization solutions, they are not capable of supporting scaling to commercialization. Hydro Ottawa was vetting local commercial design companies to combat this known

issue, but it remained a challenge for the project. The understanding of “commercial ready” at the end of Phase I was miss-understood by

The choice of targeting affordable housing does raise some problems that future projects may need to consider. Affordable housing boards seem to primarily focus on budget, equity – every tenant having the same “upgrades” and staying on a steady course, suggesting significant capital investments in order to upgrade an entire complex. This makes the economics challenging for the adoption of new technologies for improving housing conditions, especially for a customer with less access to capital. Except for the two largest agencies in Hydro Ottawa’s Service Area, they all lack in-house expertise or resources to support new technologies and would need a third party to maintain and operate throughout the asset life. While Hydro Ottawa might have been able to provide this service, local distribution companies (LDCs) in Ontario are presently only permitted to own a limited amount of generation and that can only be funded from net-profit, not rate-base. They are required to propose non-wires alternative solutions, however, that potential utility business model is presently not yet clearly developed for Ontario LDCs. Thus, the timing of this project was potentially too early for the Ontario market.

Hydro Ottawa reported great difficulty in signing and recruiting customers to participate in the demonstration of the Phase II project. Barriers to customer interest appeared to be related to ….. Ultimately, an adjustment needed to be made where 50% or more of the customer base load profiles were covered in the field trial, and DR impact was then extrapolated across the customer base.

> **Recommendation:** Communicating well and regularly with MiGen participants is critical to productive engagement. Expressions of appreciation and token gifts do lead to higher tenant satisfaction. This is a generally known important practice and is stated here as reinforcement to all on any project.

Managing a pivot to a project under a funding agreement

In principle, scope adjustment, rather than project pivoting, may have been possible while complying with the program funding and project acceptance terms and conditions. Though ultimately finalizing the neither was pursued for a number of reasons and instead Hydro Ottawa and NRCan mutually agreed to terminate the funding agreement. Re-prioritization of funding and resources to core services at Hydro Ottawa (due to the filing of its five-year custom rate application) seriously affected the progress of Phase II. During the filing period, Hydro Ottawa sought support and consultation for the MiGen project direction, but the OEB was unavailable on this specific request while rate filing was proceeding. MiGen also looked for support and funding from the IESO’s Grid Innovation Program, but the review process was unusually challenging and prolonged, leading to delays. The IESO was undergoing changes after the 2017 provincial election which caused more difficulty in seeking IESO support. It was not until late 2021 that the OEB modified it’s sandbox to be more effective for utility innovation, and the IESO began to make progress with DER and TEM.

Lacking additional direction or engagement from key stakeholders, Hydro Ottawa ultimately decided to terminate the project and consider other opportunities.

Additional Details/Reflection

Leading up to filing for an innovative project’s funding, within the company ranks there is much hope, and on receiving acceptance, much excitement. However, MiGen was a foresight project that suffered from a resignation that it did not meet immediate financial benefit and would not until the regulatory and

wholesale market matured. Like a house of cards, project support collapsed. What could have prevented the collapse, apart from what was discussed above, may be:

(1) a good collaboration environment between the regulatory, market and utility environment on innovation is necessary. The framework for this to happen and still maintain the necessary Arms length relationship is important to avoid perception of conflict of interest between the watchdog, the wholesale authority Seems in late 2021 and into 2022, the revised OEB sandbox, the involvement of the OEB in the IESO Grid Innovation Fund, and the IESO's Transmission and Distribution Working Group are good steps.

(2) dedicated corporate resourcing needs to back-up corporate support for innovative projects. A project's corporate blessing is important, however, resources to the project need to have their time dedicated as priority to the project when assigned to the project.

(3) projects deemed to be importantly transformative for future goals may benefit from a separate funding mechanism. This mechanism could reduce pressure to commercialize, involve oversight and support from the required stakeholders - that can include other utilities - for best learning, continuity and success.

(4) complex projects should be structured to sequentially complete use cases in an agile managed project manner.

(5) Time-of-Use rates are insufficient to manage the hockey-stick curve effect that electrification will bring. Data of our EVSE study customers shows that the majority of vehicle charging happens right after off-peak rates begin. Managing EVSEs would be the solution, but the hurdles remain EVSE OEMs being protective of who may manage them using their backend systems, and each OEMs system still needs its own interface.

(6) DR related solutions should allow for customer monitoring and control plus adhere to at least minimal Privacy of Information and cybersecurity principles. Though the solution should be developed to give consumers/prosumers peace of mind, it needs to be "set-and-forget" to give them comfort. Our participants were excited with the devices installed: firstly, because they could save money; secondly, because they were in control and privacy was protected; thirdly, because they were part of a nifty project. Franky, though they had opt-out control it only happened once during trials, and though they had visibility to the amount of energy generated they really only paid attention to their bill. The details of what happens behind the scenes, is not important to them so long as they are comfortable with the assurances given; the need for their devoted time to manage DR activity won't be given.

(7) Hardware vs Software solution needs more thought. A hardware solution is a complex and more costly undertaking, whereas a software or cloud based solution is quicker turnaround and less capital intensive. However, consideration is needed between trade-offs: having a trustworthy / definitive solution for protection, monitoring and control - as needed for generation systems; ease and flexibility of deployment and maintenance; resiliency and dependability for autonomous smart function during islanding, outages or central system failures; dealing with OEM devices that are not interoperable; total cost of ownership and needed ratio between capital and operating costs; and so on.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

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EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 2 / Schedule 5 / pp. 36-37 (pdf Exhibit 1 part 1, pp. 206-207)
Ref. 2: Technical Guidelines for the Approval of: Electrical Equipment, Design and Construction (Ver. 2.0)

Preamble:
Hydro Ottawa states the following.
Hydro Ottawa has assumed an average annual increase in the range of 2.1% to 5.0% with respect to the future cost of equipment and materials. This range is based on an analysis of the historical cost of equipment and materials commonly used by Hydro Ottawa.

Hydro Ottawa has negotiated escalation rates between 2.0% and 3.3% for certain outside services in support of executing OM&A capital work programs in the earlier years of the Custom IR period.

QUESTION(S):

a) Please provide the inflation factors applied to all major equipment, as defined by section 2.1.2 in reference 2, for each year of the test period.
b) Regarding outside services supporting execution of the OM&A programs, what is the percentage of forecast dollar amount of those services with whom Hydro Ottawa has negotiated 2.0-3.3% escalation rates, relative to the total forecast dollar amount?
    i) For 2026, please provide the forecast amounts of outside services, excluding all burdens and overheads.
c) Regarding outside services supporting execution of the capital programs, what is the percentage of forecast dollar amount of those services with whom Hydro Ottawa has negotiated 2.0-3.3% escalation rates, relative to the total forecast dollar amount?

i) For each year of the Custom IR period, please provide the forecast amounts of outside services, excluding all burdens and overheads.

ii) Are these negotiated price escalations included in the Custom IR period forecast? If so, what values have been used for the years that are not in "the earlier years of the Custom IR period"

RESPONSE(S):

a) With respect to the equipment listed in Section 2.1.2 of Reference 2, the inflation factor applied to all major equipment as defined by the Electrical Safety Authority is 5% annually from 2026-2030.

This is supported in Schedule 1-2-5 - Impacts of Inflationary Pressure. The general inflationary price trends in the cost of labour, commodities, industrial products, and electrical components, and Hydro Ottawa's own specific experiences noted, have impacted the cost of labour and specific products that Hydro Ottawa purchases in support of its capital projects. Below summarizes key data from 2020-2024, which was used to inform the 2026-2030 period:

- Sections 3.2 to 3.4: outline general inflationary price trends, with annual average increases ranging between 6.1% to 20% (Tables 9 to 23).
- Sections 4.1 to 4.2: outline Hydro Ottawa's specific experiences, with annual average increases ranging between 2.0% to 29.6% (Tables 25 to 31).

As Section 5.1 mentions, based on the recent historical trend, the 2026-2030 average annual increase of 5% is a conservative estimate and assumes that the inflationary pressures of recent years will partially subside for the 2026-2030 period. Section 5.2 synthesizes external general inflation forecasts to support the reasonability of Hydro Ottawa's annual inflation factor of 5% (this couples general economic data with electricity-industry-specific indices).

b) Regarding outside services supporting the execution of OM&A programs, 39% is the percentage of forecast dollar amount of those services with whom Hydro Ottawa has negotiated

2.0%-3.3% escalation rates, relative to the total forecast dollar amount. As vendor-level forecasting is not performed, this percentage was calculated using 2024 data as a proxy. To do so, Hydro Ottawa reviewed contracts with its top 10 vendors by dollars spent that extend into the 2026 test year. The resulting 39% is driven by the fact that the two largest vendors in this sample have stipulated increases that are slightly above the 3.3% range. This further supports the conservative approach to inflation described in the response to part a). It should be noted that the top 10 vendors accounted for 83% of 2024's spend.

i) In 2026, the forecasted amount of outside services, excluding all burdens and overheads, is $20.5 million relating to OM&A programs.

c) Regarding outside services supporting the execution of the capital program, 69% is the percentage of forecast dollar amount of those services with whom Hydro Ottawa has negotiated 2.0%-3.3% escalation rates, relative to the total forecast dollar amount. The same methodology from part b) above was used to determine this percentage. It should be noted that the top 10 vendors accounted for 65% of 2024's spend.

i) This is summarized in Table A below

Table A – Outside Services Excluding all Burdens and Overheads for Capital Programs ($'000s)

	Test years				
	2026	2027	2028	2029	2030
Outside services (excluding all burdens and overheads)	160,767	136,275	109,450	121,850	107,498

ii) Yes. The values used for outside services supporting execution of the capital programs are 3.25% in 2026, and 3% annually in each year from 2027 to 2030.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

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EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 6 (pdf Exhibit 1 part 1 p. 220)

Preamble:
Hydro Ottawa states "The Price Cap IR option allows Hydro Ottawa to rebase, but limits rate increases in the outer years of the rate period to inflationary adjustments. This constraint poses a significant challenge for Hydro Ottawa given that its service territory is experiencing accelerated electrification and unprecedented levels of growth."

QUESTION(S):

a) Has Hydro Ottawa considered what Price Cap IR formula parameters would need to be modified for the Company to manage under a Price Cap IR option? If so, what tweaks on the current construct would be required for Hydro Ottawa to manage over a five-year period under the Price Cap option?

RESPONSE(S):

Most notably missing from the price cap model is the impact of growth and electrification while also facing the replacement of aging infrastructure. The price cap model has been designed for steady growth and costs. Hydro Ottawa's proposal is instead driven by the principle that significant investments are required to both manage growth in the distribution system and maintain aging infrastructure. This underlying message has been expressed throughout the DSP and supplemented through interrogatory responses.

Tables A below display Hydro Ottawa's illustrative Base Revenue Requirement over the 2027-2030 period, using Hydro Ottawa's inflationary projection of 2.1% in the OEB Price Cap for all years. Tables A also includes Hydro Ottawa's Efficiency Assessment as Cohort III and Cohort IV for illustrative purposes, although please note Hydro Ottawa is proposing to use the Cohort III stretch for all five years.

Table A - Illustrative 2026-2030 Base Revenue Requirement under Price Cap IR Parameters - Inflationary Assumption of 2.1% ($'000s)

	2026	2027	2028	2029	2030	TOTAL
Cohort III						
Cohort III - 0.30%	$297,170	$302,519	$307,965	$313,508	$319,151	**$1,540,314**
HOL Proposed	$297,170	$320,499	$351,913	$376,083	$399,887	**$1,745,551**
DEFICIENCY	**$0**	**$17,979**	**$43,948**	**$62,575**	**$80,735**	**$205,237**
Cohort IV - 0.45%	$297,170	$302,074	$307,058	$312,124	$317,274	**$1,535,701**
HOL Proposed	$297,170	$320,499	$351,913	$376,083	$399,887	**$1,745,551**
DEFICIENCY	**$0**	**$18,425**	**$44,855**	**$63,959**	**$82,612**	**$209,851**

As shown in Table A, under a standard Price Cap IR, Hydro Ottawa would face a significant revenue deficiency of $205M over the 2026-2030 period, with the precise amount depending on inflation parameters and accepted efficiency rating. As detailed in Schedule 1-3-1 - Rate Setting Framework, this substantial shortfall arises because the standard Price Cap IR, while allowing for rebasing, fundamentally limits rate increases in the outer years to inflationary adjustments. This constraint poses a critical challenge for Hydro Ottawa, given the accelerated and unprecedented levels of growth and electrification currently transforming its service territory. The significant capital investments essential for expanding and modernizing the grid for the future cannot be adequately funded under the standard Price Cap IR option. Specifically, the Advanced Capital Module (ACM) available under Price Cap IR is incompatible with the large, multi-year, and often "lumpy" capital investments required for projects such as ADSM, DERMs and the development of DSO capabilities. ACM's reliance on annual regulatory approvals introduces regulatory costs and uncertainty that

would severely hinder Hydro Ottawa's ability to complete the necessary work to serve its customers and prepare its grid for electrification.

Therefore, for Hydro Ottawa to effectively manage its base Revenue Requirement under a Price Cap IR framework, the following key modifications to the standard construct would be required:

- **Enhanced Mechanism to account for large, multi-year capital investments**
  Beyond the existing ACM option, the Price Cap IR framework would require significantly expanded mechanisms to accommodate large, multi-year capital investments, particularly those that are "lumpy" in nature. These mechanisms, available under a Custom IR framework, are essential to enable to necessary investments in grid resilience, growth-related infrastructure and advanced technologies that are critical for meeting evolving system needs - particularly those substantial, multi-year projects that extend beyond a single rebasing cycle (e.g. ADMS, DERMs, DSO capabilities, etc).

- **Dynamic OM&A Adjustment for Growth**
  The OM&A component of the Price Cap IR framework would need to incorporate a specific growth or complexity factor that would allow for adjustments to OM&A revenue that accurately reflect actual increases in customer count, system capacity, and the operational demands associated with grid modernization and DER integration.

- **Explicit Incentives and Cost Recovery for NWS and Electrification**
  Custom deferral and variance accounts would be more difficult under a Price Cap IR framework, explicit mechanisms would need to exist to incentivize and recover costs associated with NWS and other electrification initiatives.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

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EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / Table 1 / p. 8 (pdf Exhibit 1 part 1 p. 222)

Preamble:
In addition to several proposed asymmetrical variance accounts, Hydro Ottawa proposes to operate with three symmetrical capital variance accounts, as follows:

- Connection and Cost Recovery Agreement (CCRA) Variance Account
- Non-Wires Solutions (NWS) Variance Account
- Large Load Revenue Variance Account

QUESTION(S):

a) What is the percentage of total gross capital spending that Hydro Ottawa expects to fall within these capital variance accounts?
b) Do these variance accounts reduce the cost efficiency incentives of Hydro Ottawa's Custom IR framework? If not, why not?

RESPONSE(S):

a) Total gross capital expenditures are expected to be $1.4B over the rate term, while CCRA capital expenditures are expected to be approximately $45.9M over the rate term. Therefore CCRA capital expenditures are expected to be about 3% of total gross capital spending for inclusion in the CCRA variance account. Hydro Ottawa expects 0% of total gross capital spending to fall within the Non-Wires Solutions (NWS) Variance Account and Large Load Revenue Variance Accounts since those accounts are proposed to capture NWS costs in other

revenues and OM&A and revenue variances associated with differences in volume and timing of large loads adjusted into the load forecast respectively, as outlined in Table 1 of Section 3 in Schedule 1-3-1 - Rate Setting Framework, and Sections 2.1 and 2.2 of Schedule 9-2-1 New Deferral and Variance Accounts.

b) No, in Hydro Ottawa's opinion these variance accounts do not reduce the cost efficiency incentives of Hydro Ottawa's Custom IR framework. Please see further discussion below for each account.

Connection and Cost Recovery Agreement (CCRA) Variance Account

The CCRA Variance Account is a symmetrical account that trues-up the difference between the estimated costs and actual costs of Hydro One payments. The need for CCRA payments is driven by organic customer growth, new customer connection requests and City planning that results in the need for transmission upgrades and required capacity forecasts for 15 years. The predictability of timing of load is more difficult to estimate as they are impacted by changes in customer long-term development plans, conservation activities, generation connections (including behind the meter generation), and the pace of electrification. The main factors of these decisions are not driven by Hydro Ottawa's cost efficiency but rather customer economic factors and government policy objects and incentives. In addition, although Hydro Ottawa monitors the costs Hydro One charges through CCRA arrangements and works with Hydro One for the optimal solution, the main efficiency incentives of these costs are established as part of Hydro One's rate Application process. Please also see Attachment 1-3-3(A) - PEG Benchmarking Analysis.

Lastly, variance accounts essentially go through two review processes, once when the original costs and timing are proposed and again when any variance is requested to be disposed of.

Non-Wires Solutions (NWS) Variance Account

The Non-Wires Solutions Variance Account addresses a developing policy area. The regulatory framework for NWS, particularly the comprehensive cost-benefit analysis requirements, has

only recently been finalized by the OEB and will be implemented for applications filed in 2026. This nascent stage of policy development means that the full implications for cost recovery and efficiency incentives are still evolving. Without a dedicated variance account, Hydro Ottawa would need to be limited by the proposed financial investment mix as proposed, while policy, benefits, funding and remunerations are evolving. This uncertainty could act as a disincentive and discourage the pursuit of innovative and often capital-deferring solutions, thereby hindering the very efficiency gains and system benefits NWS are intended to deliver. The NWS Variance Account therefore ensures that Hydro Ottawa can pilot and implement NWS without being financially penalized for the evolving nature of NWS.

Large Load Revenue Variance Account

The Large Load Revenue Variance Account is crucial for managing the financial impacts of significant new electrical connections from large load customers, driven by growth and electrification that has not been previously experienced. As far as it is aware, Hydro Ottawa is the first LDC in Ontario to proactively include such increased demand in its load forecast for new multiple large connections. These projects can introduce substantial and potentially unpredictable revenue streams. A dedicated variance account ensures that the financial impacts of these large, often lumpy, connections are accurately captured and reconciled, preventing unintended over- or under-recovery.

Hydro Ottawa will not have reduced cost efficiency incentives as increased costs of most projects above the capital proposed will be borne by Hydro Ottawa in the short term. In addition, the variance account is intended to capture the revenue difference of timing of load which will be dictated by the customer’s project management and decisions.

It should be noted that Hydro Ottawa has not requested a variance account for the smaller electrification embedded in the load forecast and only major projects which inherently have more delays and uncertainty.

It is important to note that all three of these variance accounts are designed with symmetry, meaning they can result in funds being returned to customers if forecast timing or investment needs lead to less expenditures than anticipated or more revenue collected. This mechanism ensures ratepayers are also refunded for projects that are less predictable to forecast costs and revenues, while the projects are essential in meeting customers demands and achieving government policy objectives. These proposed accounts maintain the integrity of the Custom IR framework's commitment to cost efficiency and customer value for all ratepayers.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

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EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 8 (pdf Exhibit 1 part 1, p. 222)
Ref. 2: Exhibit 1 / Tab 3 / Schedule 1 / p. 15 (pdf Exhibit 1 part 1, p. 229)

Preamble:
In reference 1 Hydro Ottawa has stated the 2026 test year capital forecast includes a stretch of $6.9M that is embedded through identified efficiencies. Table 3 and Table 4 in reference 2 show the total stretch over the forecast period in the capital budget is $35M which equates to an average revenue requirement stretch of 0.65%.

QUESTION(S):

a) Please produce the data shown in Table 3 and Table 4, on an annual basis, in the tables below.

Table: Capital Expenditures				
Year	Required Capital Expenditures $000	Proposed Capital Expenditures $000	Stretch $000	Stretch %
2026				
2027				
2028				
2029				

2030				

Table: Capital Related Revenue Requirement				
Year	Required Revenue Requirement $000	Proposed Revenue Requirement $000	Stretch $000	Stretch %
2026				
2027				
2028				
2029				
2030				

RESPONSE(S):

Please see requested Tables A and B below. Please note that the breakdown provided reflects the capital expenditures, productivity and revenue requirement submitted in the original application. Revisions made to those amounts since submission have not been reflected for the purposes of detailing the calculation method and reconciling to the referenced amounts.

Table A - Capital Expenditures

Capital Expenditures				
Year	Required Capital Expenditures $000	Proposed Capital Expenditures $000	Stretch $000	Stretch %
2026	$264,844	$258,171	-$6,673	-2.52%
2027	$266,967	$260,390	-$6,577	-2.46%
2028	$227,016	$217,532	-$9,484	-4.18%
2029	$241,739	$235,478	-$6,261	-2.59%
2030	$229,778	$223,700	-$6,078	-2.65%

Table B - Capital Related Revenue Requirement

Capital Related Revenue Requirement				
Year	Required Revenue Requirement $000	Proposed Revenue Requirement $000	Stretch $000	Stretch %
2026	$166,371	$165,392	-$979	-0.59%
2027	$184,700	$183,581	-$1,120	-0.61%
2028	$209,956	$208,388	-$1,568	-0.75%
2029	$225,897	$224,417	-$1,480	-0.66%
2030	$241,622	$240,039	-$1,584	-0.66%

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-9

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 9 (pdf Exhibit 1 part 1, p. 223)

Preamble:
As part of the proposed 2026-2030 Customer IR Rate Framework, Hydro Ottawa states that for Other Revenue, it set both rates and revenue for 5 years. Where rates are proposed to be adjusted in years 2 to 5 based on inflation, set rate of 2.1% for all four years (no adjustment based on the OEB approved inflation factor).

QUESTION(S):

a) Please explain Hydro Ottawa's assumptions used to derive the inflation rate of 2.1% for the 2027 to 2030 period.

RESPONSE(S):

Hydro Ottawa utilized the OEB's sector-specific inflation assumptions to calculate an average annual inflation rate of 2.1% for 2027-2030. For both labour and the non-labour components, Hydro Ottawa used the Conference Board of Canada's forecast for Ontario's Final Domestic Demand and Ontario's Average Weekly Wages and Salaries per Employee.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-10

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / Table 1 / p. 9 (pdf Exhibit 1 part 1, p. 223)

Preamble:
Table 1 compares growth factor G used to adjust the OM&A Funding for years 2-5 in the 2021-2025 and proposed 2026-2030 Custom IR Rate Framework. In the 2021-2025 rate framework G is calculated using forecasted customer growth rate based on the 2021-2025 load forecast multiplied by a 0.35 scaling factor. In the proposed 2026-2030 rate framework, G is calculated using forecasted customer and system capacity growth, weighted using the assumptions in the OEB's cost allocation model for OM&A.

QUESTION(S):

a) Please explain why a scaling factor is not included in the proposed 2026-2030 rate framework.
b) The growth factor of 3.23% is a cost-weighted average of forecasted customer and system capacity growth. Please provide the calculations for a growth factor that is a revenue-weighted average of these values, rather than cost-weighted.
c) Please explain why the growth factor is based on a forecast that is static over the five-year term and does not contain a true-up to actual values each year of the plan.

RESPONSE(S):

a) As detailed in Schedule 1-3-1 - Rate Setting Framework, the growth factor used to adjust the OM&A funding for years 2-5 of the 2026-2030 rate period is designed to fund incremental OM&A costs associated with Hydro Ottawa's rapid growth and electrification. This growth factor

is derived from increases in both customer count and system capacity, calculated based on the forecast CAGR for the 2025-2030 period.

Notably, the growth factor utilized in Hydro Ottawa's Custom Price Escalation Factor (CPEF) in years 2-5 of its 2021-2025 rate period was based exclusively on projected customer count growth. A scaling factor was then employed to account for economies of scale, recognizing that relying solely on customer count might not fully reflect the proportional increase in all OM&A activities.

A scaling factor was not proposed in years 2-5 of Hydro Ottawa's 2026-2030 CROF, as in this case, Hydro Ottawa has directly applied the assumptions from the OEB's cost allocation model to derive appropriate weightings for customer count growth versus capacity growth. This approach resulted in a weighting of 45.2% for customer count growth in its G factor. By leveraging the OEB's cost allocation model assumptions, the growth factor more accurately reflects Hydro Ottawa's unique system makeup and the costs attributable to both customer count and capacity growth.

b) A revenue-weighted growth factor was not proposed because it does not align with the fundamental cost drivers and planning conditions on which Hydro Ottawa's rate application is based. Our proposal is instead driven by the principle that significant investments are required to both manage growth in our distribution system and maintain aging infrastructure.

This disconnect between revenue and costs is evident in several key areas:

- **Residential Electrification:** Residential demand (for electric vehicles and heat pumps) requires major system investments. However, the revenue structure is fixed and does not scale proportionately with this demand.
- **Large Load Investments:** Large new load requests necessitate significant capital investments that may not be fully captured by billing determinants over the rate period.
- **Commercial Customer Trends:** For the small commercial class, customer count is forecast to increase, while energy consumption (kWh) is projected to decrease due to conservation

impacts. This creates a direct mismatch between the cost driver (customer count) and the revenue stream (consumption).

A revenue-based growth factor would be more appropriate for an IRM application, which assumes stable growth and is primarily based on inflation. A Custom IR rate application, however, is better suited for periods of non-linear cost growth and heavy investment to serve future needs.

Table A below calculates a revenue-weighted growth factor as requested. Please see Attachment 1-Staff-10(A) - Revenue Based Weighting Growth to the integrity for the calculations.

Table A - Revenue-Weighted Growth Factor

	2026	2030	Revenue weighting	CAGR
kWh Capacity	3,338,442	3,450,823	9.0%	0.831%
kW Capacity	9,582,951	9,889,778	24.8%	0.791%
Customer	377,702	392,598	66.2%	0.972%
Weighted Growth Rate				**0.91%**

c) The fixed growth factor ensures stable and predictable rates over the term, allowing both customers and the utility to plan and manage operational budgets and investments. In multi-year rate cycles, fixing various assumptions streamlines the rate setting process for the IR term. Adjusting the growth factor annually would add unnecessary complexity in setting rates and managing operational budgets.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-11

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / Attachment A / p. 11-12 (pdf Exhibit 1 part 1, p. 330-331)
Ref. 2: Exhibit 1 / Tab 3 / Schedule 1 / Attachment A / Table 5 / p.13 (pdf Exhibit 1 part 1, p. 332)

Preamble:
With regard to the lost kilowatt-hour demand due to conservation and demand management (CDM), Hydro Ottawa states the following.

> The practical effect is that Hydro Ottawa's kWh deliveries and annual peak demand (capacity) have been offset by CDM from 2010 to the present, affecting the utility's cost structure. However, an explanatory variable for CDM is missing from the PEG Model. Consequently, a program that has significantly impacted customer demand and utility costs is not captured in the PEG Model, resulting in underreported predicted costs…
>
> Although Hydro Ottawa's load has been relatively flat for over ten years, its electrified service territory has expanded. The PEG Model, however, does not accurately reflect the reasonable costs associated with this growth in the predicted model.

QUESTION(S):

a) Please explain how CDM has impacted the utility's cost structure.
b) Please provide supporting calculations and documentation to compute deliveries (kWh) and peak load (kW) adjusted for CDM in reference 2.
c) Please explain how the growth of electrified service territory can be accommodated in the model by adding in CDM program energy savings as shown in reference 2.

RESPONSE(S):

a) CDM effects have imposed indirect costs on the distributor through unused capacity.

Hydro Ottawa understands that the PEG parameters are a measure of the relationship between electricity consumption (deliveries), notional network capacity, and the utility's costs arising from those activities on the margin. In other words, an incremental kWh delivered or kW of capacity will produce additional costs in PEG's prediction based on the operational conditions between 2002 and 2012, when that relationship was measured.

However, since 2012, CDM has constrained growth in kWh deliveries and capacity by reducing per-customer consumption. As a result, the observed cost drivers in the PEG model are artificially suppressed, even as Hydro Ottawa's actual service obligations have continued to grow through:

- The addition of new customers,
- Expansion of its geographic service territory, and
- Increased system renewal and modernization requirements.

All things being equal, the notional costs of connecting an incremental customer are unchanged since 2012. That is, while PEG's model predicts lower costs for incremental customers based on their reduced electricity consumption, the actual capital and operating costs required to serve those customers (i.e., transformers, poles, meters, and service connections) remain constant or have increased.

The disconnect between predicted and actual costs has led to an underestimation of Hydro Ottawa's predicted costs in the PEG model and contributes to an increasing variance between predicted and actual total costs. This gap represents the cost of underutilized capacity that has been added to the network but not fully activated due partially to CDM-driven demand reductions

The OEB has acknowledged this cost relationship in residential fixed rate design as part of EB-2012-0410, A New Distribution Rate Design for Residential Electricity Customers. As stated in the report, the rate design was partially implemented to "Enable customers to leverage new technologies" and to "Help customers better understand the value of electricity service"[1] and goes on to say "For example, no matter how much electricity a residential customer uses, that customer still needs a meter, a connection to the nearest distribution pole, the poles and wires that bring electricity from the bulk system, and a place in the customer service computer system."

The same principle applies here: CDM may reduce load, but the physical infrastructure and service obligations do not scale down proportionately. As a result, the PEG model, while valuable, does not fully capture the cost implications of connecting and maintaining service to customers in an environment shaped by sustained CDM impacts.

b) Hydro Ottawa has attached the CDM delivery and capacity supporting data in Excel Attachment 1-Staff-11(A) - CDM Supporting Data. The data originates from the Lost Revenue Adjustment Mechanism (LRAM) inputs used to support Hydro Ottawa's LRAM disposition. Specifically, the figures represent net savings rather than gross savings, offering a conservative estimate of conservation impacts by accounting for adjustments that reduce overall savings. A summary of the calculation, adding CDM to deliveries and capacity, is provided in Table A below.

[1] Ontario Energy Board, *Board Policy - A New Distribution Rate Design for Residential Electricity Customers*, EB-2012-0401, (April 2, 2015), page 5

Table A - Supporting Calculations Computing Updated Delivery Volume and Annual Peak Demand (Capacity) for CDM

Output and Other Business Conditions	Calculation	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
Delivery Volume	a	7,284,318,125	7,362,316,227	7,338,616,990	7,342,961,578	7,392,374,188	7,403,746,762	7,417,466,427
Conservation Demand Management (CDM) Delivery Volume	b	552,879,804	518,894,744	502,714,625	467,297,770	434,991,535	374,843,961	299,790,956
Total CDM updated Delivery Volume	c = a + b	7,837,197,929	7,881,210,971	7,841,331,615	7,810,259,348	7,827,365,723	7,778,590,723	7,717,257,383
Annual Peak Demand (without embedded)	a	1,535,182	1,540,271	1,554,905	1,569,717	1,584,826	1,599,027	1,614,519
Conservation Demand Management (CDM) kW	b	100,733	102,023	105,336	104,653	105,446	99,934	95,643
Updated Annual Peak Demand (without embedded)	c = a + b	1,635,915	1,642,294	1,660,241	1,674,370	1,690,272	1,698,961	1,710,162
Average ratio (2018 to 2023) of Annual Peak Demand with embedded versus without embedded	d	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Updated Annual Peak Demand CDM (with embedded)	e = c * d	1,575,829	1,581,974	1,599,262	1,612,871	1,628,189	1,636,560	1,647,349

c) Hydro Ottawa does not intend to account for the growth in its electrified service territory in the PEG model by adding delivery kWh and capacity kW savings due to CDM. Instead, the addition of CDM deliveries and capacity aims to account for costs that would have otherwise been accounted for in the PEG model's prediction had CDM programs not existed related to historical growth. Specifically, CDM initiatives were not prevalent during the PEG model's regression period from 2002 to 2012, and the model itself does not explicitly include a parameter to account for CDM impacts. As a result, the PEG model's baseline forecasts exclude the conservation effects seen in more recent years. By adding back CDM savings, Hydro Ottawa aims to represent the costs associated with reduced demand (the unused capacity that distorts the utility's cost structure). This unused capacity effectively increases the per-unit cost of new infrastructure and operations, since fixed costs are spread over lower consumption volumes.

The inclusion of CDM deliveries and capacity in the analysis serves to adjust for these historical distortions, ensuring that cost assessments better reflect the reality of deferred or avoided infrastructure investments and the true economic impact of CDM on the system.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-12

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / pp. 19-20 (pdf Exhibit 1 part 1, pp. 233-234)

Preamble:
With regard to its proposed inflation factor, Hydro Ottawa states the following:
For the purposes of rate modelling provided in this Application, Hydro Ottawa used a forecasted inflation factor of 2.10%. However, consistent with standard OEB policy, in years two to five of the custom rate period (i.e. 2027-2030) Hydro Ottawa intends to update the inflation factor included in the proposed CROF through the annual rate application process. This update will be based on the OEB-inflation factor, which is derived from the weighted sum of two distinct sub-indices:

- Non-Labour Index: 70% of the annual percentage change in Canada's Gross Domestic Product Implicit Price Index (GDP-IPI) Final Domestic Demand (FDD), as officially reported by Statistics Canada; and
- Labour Index: 30% of the annual percentage change in the Average Weekly Earnings ("AWE") for workers in Ontario, as officially reported by Statistics Canada.

QUESTION(S):

a) What is the weight of labour and non-labour costs related only to OM&A at Hydro Ottawa?

RESPONSE(S):

a) The request information is included in Section 5.1 of Schedule 1-2-5 - Impacts of Inflationary Pressure. Labour costs represent 54% and non-labour costs represent 46% of Hydro Ottawa's average OM&A budget for 2026-2030.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-13

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 20 (pdf Exhibit 1 part 1, p. 234)

Preamble:

With regard to its proposed productivity factor, Hydro Ottawa states the following:

> Consistent with the OEB's Rate Setting Parameters and Benchmarking under the RRF, Hydro Ottawa proposes to adopt the OEB's TFP factor of 0% in its CROF, but notes that the effect of increasing the productivity factor to zero creates an additional stretch factor during the term of this application.

QUESTION(S):

a) Did Hydro Ottawa calculate a partial productivity factor (PFP) for the purposes of setting the revenue cap on OM&A-related revenue?
b) If so, what was the calculated value of industry PFP growth?

RESPONSE(S):

a) Hydro Ottawa did not calculate a partial productivity factor. The reference is pointing to the conclusion the OEB made in its report, *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. Specifically, on page 17 the following is stated:

> *The Board believes that setting the productivity factor at zero reflects a reasonable balance of the estimated productivity trend in the sector over*

> *the last 10 years and a value that is reasonable to project into the future as an on-going external industry benchmark which all distributors should be expected to achieve.*
>
> *The Board acknowledges that achieved productivity growth in the Ontario distribution sector has likely slowed in recent years. However, the Board does not believe it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future.*[1]

The statement above acknowledges that the industry is in a state of productivity decline, therefore when the Board set a stretch factor at zero, it inherently created a stretch factor for distributors to achieve. This observation was also made on on page 18:

> *At the Stakeholder Conference and in the subsequent written comments, distributors expressed the view that setting the productivity factor to zero when estimated TFP growth is negative constitutes an implicit stretch factor in the X-factor.*[2]

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

[1] Ontario Energy Board, *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,* EB-2010-0379 (November 21, 2013; corrected December 4, 2013), page 17.
[2] Ibid., page 18.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-14

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 21 (pdf Exhibit 1 part 1, p. 235)

Preamble:
Hydro Ottawa has identified three data elements that had a substantive adverse impact of its efficiency performance assessment due to the omission from the PEG Model. These elements are as follows:

1. Secondary Circuit kilometers not being included in the Circuit Kilometers metric;
2. To capture impacts of CDM on a utility's cost drivers; and
3. The exclusion of Other Revenue with the PEG Model while certain costs associated with Other Revenue are included in OM&A and capital.

QUESTION(S):

a) Is Hydro Ottawa aware of any other Ontario electricity distributors that also have adjusted the PEG model to
   i) omit circuit kilometers that should be reflected in the total circuit kilometers model variable?
   ii) omit lost kWh and demand due to CDM?
   iii) omit costs associated with other revenues that should not be interpreted as inefficiency, like move-in and move-out costs or property rentals?

Please explain responses above.

RESPONSE(S):

a)

i) Hydro Ottawa is aware of two utilities, Alectra Utilities Corporation and Greater Sudbury Hydro Inc., that submitted secondary circuit kilometers to the OEB, which had been previously omitted. The inclusion of these secondary circuit kilometers in the PEG model resulted in improved efficiency scores in both instances.

First, Alectra Utilities Corporation is an amalgamation of numerous legacy utilities, some of which reported secondary circuit kilometer line data to the OEB as part of their Reporting and Record-keeping Requirements (RRR), while others did not. According to the PEG's Benchmarking Update Calculation 2024, Alectra was incorporated in 2017 and reported total circuit line kilometers of 19,779. However, in 2019, Alectra reported total circuit kilometers of 49,610. The stark increase in total circuit kilometers was due to the inclusion of secondary circuit kilometers. In that same period, Alectra went from an annual efficiency score of 4.45% in 2017 to 0.14% in 2019. The inclusion of secondary circuit kilometers produced a positive effect on PEG model efficiency. Table A below summarizes Alectra's changes in circuit kilometer reporting and efficiency scores.

Table A - Alectra Utilities Corporation's Historical PEG Circuit Kilometers and Annual Efficiency Score

	2017	2018	2019	2020
Total Primary Circuit Kilometers	19,779	19,897	21,112	21,171
Total Secondary Circuit Kilometers	N/A	N/A	28,498	28,307
Total Circuit Kilometers	19,779	19,897	49,610	49,478
Annual Efficiency Score	4.54%	-0.68%	0.14%	-4.41%

Second, in 2024, Greater Sudbury Hydro Inc. submitted corrections to the OEB at its invitation. Greater Sudbury Hydro's revised data included secondary circuit kilometers dating back to 2019, according to the OEB's open data inventory.[1] In PEG's 2023

[1] Ontario Energy Board, Open Data, Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.5.5 Utility Characteristics, https://www.oeb.ca/ontarios-energy-sector/open-data.

benchmarking report, it addressed the impact of the data revisions and restated Greater Sudbury Hydro's historical PEG results for informational purposes.[2]

Greater Sudbury Hydro's revised efficiency scores for 2020, 2021, and 2022 improved as a result, as summarized in Table 3b of the report, and below in Table B.

Table B - Greater Sudbury Hydro Inc. Revised Data on Cost Performance Results

2020 Cost Performance			2021 Cost Performance			2023 Cost Performance		
Previously Calculated	As Revised	Difference	Previously Calculated	As Revised	Difference	Previously Calculated	As Revised	Difference
3.0%	0.4%	2.65%	1.4%	-3.1%	4.44%	-3.8%	-7.9%	4.14%

Although Greater Sudbury Hydro reported secondary circuit kilometers back to 2019, PEG's Benchmarking Update Calculation does not account for the restated secondary circuit kilometers until 2022, when the utility's total circuit kilometers go from 1,019 kilometers in 2021 to 2,547 kilometers in 2022. This example demonstrates PEG's acknowledgment of previous years' secondary circuit kilometers as a correction and the effects on a utility's annual efficiency score.

The important distinction is that these secondary circuit kilometers and their associated costs existed before the reported years for Alectra Utilities and Greater Sudbury Hydro, impacting the average line kilometers going back to 2002. However, the OEB does not restate previous years' circuit kilometers and their averages to avoid retroactive ratemaking. Hydro Ottawa contends that the restating of historical years is necessary to assign future efficiency scores because it so strongly influences the model's predictive accuracy through the average circuit kilometers business condition.

ii) All utilities in Ontario omit the effects of Conservation and Demand Management on their deliveries (kWh) and capacity (kW). An additional step would be required to add back in

[2] Pacific Economies Group Research, LLC, *Empirical Research in Support of Incentive Rate-Setting: 2023 Benchmarking Update - Report to the Ontario Energy Board* (July 2024), Table 3b, page 19.

and quantify the loss of load resulting from the programs. The RRR does not provide an exception, nor does the PEG Model account for CDM's effects on the model. Depending on the achieved CDM savings, historical investments in the system at the time the regression model started (excess capacity) and level of growth in a utilities services territory, different levels of impact will be felt by the utilities.

iii) All utilities in Ontario submit Other Revenues as part of their annual RRR. However, the PEG Model omits these auxiliary revenue programs while accounting for their costs. However, the amount of other revenue expenses that distributors are recording in OM&A or Other Revenue will influence outcomes.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-15

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / p. 23 (pdf Exhibit 1 part 1, p. 237)
Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / Attachment A / Table 2 / p. 3 (pdf Exhibit 1 part 1, p. 322)

Preamble:
Hydro Ottawa states:

> Hydro Ottawa has already embedded productivity into the 2026 OM&A Test Year forecast. As an example, Hydro Ottawa set an ambitious stretch target of 80% for online billing adoption by the end of 2025, and built the associated savings into its 2026 base OM&A as a direct benefit to customers. As a result, the utility assumes a significant financial risk of managing the incremental printing, postage and other related costs should this ambitious target not be met or sustained over the rate term. This is only one of the examples of 2026 base rate stretch already built into Hydro Ottawa's 2026 base OM&A. Based on only the quantifiable productivity savings estimated for 2026 in Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement, Hydro Ottawa has calculated that the base year OM&A has been reduced by 2.3% which results in a 2027 to 2030 additional annual stretch already embedded in OM&A of 0.61%.
>
> Recognizing the significant savings that have already been embedded in Hydro Ottawa's proposed OM&A while recognizing the principle of the RRF, Hydro Ottawa proposes to cap the reduction of the adjusted PEG Model Stretch of 0.30% by 0.15% resulting in an X factor of 0.15% in the CROF formula. However, in total Hydro Ottawa will have an actual stretch factor in the 2027 to 2030 years of 0.76% (0.15% plus 0.61% embedded in the 2026-2030 OM&A forecast).

QUESTION(S):

a) Hydro Ottawa states that its embedded stretch factor arises from efficiencies like its target for online billing adoption. Please list the other known cost efficiencies behind this proposed 2.3% reduction in base year OM&A, and how much savings Hydro Ottawa has assumed for each relative to what would otherwise be required.

b) Please provide the calculation for the annual embedded stretch of 0.61%, based on the OM&A base year reduction of 2.3%.

c) The Adjusted PEG Model produces a stretch factor of 0.30%, but Hydro Ottawa proposes a stretch factor different from this value: a value of 0.15%. Please provide the calculations used to determine this stretch factor of 0.15%.

d) Please confirm that according to the projected results of the Adjusted PEG model, Hydro Ottawa is expected to be in Group 4 in 2029 and 2030.

e) Please confirm that Hydro Ottawa does not plan to adjust its stretch factor during the rate term even if the benchmarking results indicate that the Company's cost efficiency group changes.

RESPONSE(S):

a) Please refer to Tables 2 and 4 of Schedule 1-3-4 - Facilitating Innovation and Continuous Improvement for a list of the productivity initiatives that have been considered in the 2.3% reduction in base year OM&A. Please also refer to the response to interrogatory 1-Staff-3 for details specific to OM&A productivity initiatives in the 2026 base year. Lastly, please refer to the responses to interrogatories 1-SEC-25 and 1-SEC-27 for further details on OM&A productivity savings per year.

b) Please refer to Hydro Ottawa's response to interrogatory 1-CCC-2.

c) Please see Schedule 1-3-1 - Rate Setting Framework Table 1, page 9 that states: "X = 0.15%, based on the outputs of the adjusted PEG's Model (Attachment 1-3-3 (A) - PEG Benchmarking

Analysis) with an adjustment to recognize the embedded stretch productivity in base OM&A capped at maintaining a 0.15% stretch factor".

In addition, please see Table 6 in Section 3.2 OM&A Funding in Schedule 1-3-1 - Rate Setting Framework, which states: "Two components: Productivity factor of 0%; Stretch Factor as per PEG Model of 0.30% reduced by embedded productivity in test year (capped at 0.15%); fixed throughout the term."

As noted in the preamble Hydro Ottawa embedded a reduction in OM&A that resulted in a stretch of 0.61%.

d) Hydro Ottawa confirms that, according to its PEG model submission, it is expected to be in cohort 4 in 2029 and 2030. However, if the additional capacity required to be built over the next five years to support growth in Hydro Ottawa's service territory were incorporated into the model, Hydro Ottawa would be expected to be in cohort 3. As noted in Attachment 1-3-3(A) - PEG Benchmarking Analysis, the PEG model does not account for future growth investments.

e) Hydro Ottawa confirms that it does not plan to adjust its stretch factor during the rate term even if the benchmarking results indicate that the utility's cost efficiency group changes. Please note the cap of the embedded productivity offsets this outcome. Please also refer to part (d) to this interrogatory response.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-16

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / pp. 24-25 (pdf Exhibit 1 part 1, pp. 238-239)

Preamble:
Hydro Ottawa is proposing a growth factor based on customer growth and system capacity growth. The system capacity growth is based on the addition of 594.9 MVA of continuous rating capacity, which is the difference between the 2030 continuous rating capacity of 2,723 MVA and the 2025 capacity of 2,128 MVA as shown in Table 8 – 2025-2030 Forecast System Capacity (MVA).

QUESTION(S):

a) What criteria has Hydro Ottawa used to determine when capacity has been added to the system per Table 8? For example, is the capacity considered added when a new station is energized, when the substation is energized and all feeders are constructed and energized, or some other measure? Will the same criteria be used for each new station? Please describe in detail.
b) How has the addition of non-wires solutions been included in the Forecast System Capacity? Please describe in detail as in the previous question.

RESPONSE(S):

a) Hydro Ottawa defines capacity as added to the system when new substations are energized, or when existing substations (that undergo major upgrades resulting in an increase in capacity) are energized. The successful energization and commissioning of main power transformers, switchgear, and their associated protection, control, and station service systems are essential to achieving this expanded capacity.

Feeder integration, while a crucial downstream activity, is not the determining factor for when system capacity is considered "added" at the substation level. Feeder construction and energization are managed on an as-needed basis to connect new or growing load requirements from specific customers or for general organic growth, aligning with their individual power requirement timelines. The capacity at the substation is available once its core components are energized and commissioned, irrespective of the immediate full utilization of all potential feeders.

The same criteria outlined above was consistently applied for each new station and substation upgrade project undertaken by Hydro Ottawa.

b) Capacity added due to utility-owned Battery Energy Storage Solutions (BESS) has been included in the forecasted system capacity, and will be considered available once the BESS is energized and fully commissioned to provide grid support and capacity. As per page 8 of Section 2.1 in Schedule 2-5-8 - System Service Investments, the Non-Wires Customer Solutions Program is also included in capacity planning calculations. Hydro Ottawa plans to add 20-30MW of additional capacity from this program, primarily in the Kanata North and Core & West 13kV regions, as per Table 3 in Section 2.6.1 of Schedule 2-5-8 - System Service Investments. This is in addition to the added capacity through BESS at specific substations.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-17

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / pp. 26-28 (pdf Exhibit 1 part 1, pp. 240-242)
Ref. 2: Framework for Energy Innovation 2.0: Non-Wires Solution Incentives (Margin on Payments)

Preamble:
Hydro Ottawa is proposing an Earnings Sharing Mechanism (ESM) as outlined in reference 1. On May 16, the OEB has issued a Notice of Proposal to amend the Distribution System Code to establish a methodology for the setting of rates to include a margin on payments incentive to use third-party distributed energy resources (DERs) as non-wires solutions to meet an electricity distribution system need.

QUESTION(S):

a) Under Hydro Ottawa's proposal, would any margin on payments incentive received pursuant to the Distribution System Code be included as earnings eligible for sharing under the ESM. If not confirmed, please provide rationale.

RESPONSE(S):

a) No, the intent of the margin on payment (MoP) is to replace the return on equity that a utility would have earned on a wired investment. Its purpose is to incentivize utilities to adopt non-wires solutions (NWS) by compensating for the innovation risk and investment. Unlike traditional wired infrastructure, NWS do not contribute to the rate base, which is the foundation for a utility's ROE calculation. The MoP should instead be considered within a dead band, a range where no earnings sharing is triggered. This allows the utility to retain the full benefit of

the MoP, ensuring the incentive remains intact. Without this mechanism, a utility would have no base return on its investment and risk, making NWS a less attractive option. For example, if a utility chose an NWS or switched from a traditional wired solution, the MoP would fall within the dead band, and no earning sharing would be triggered. This ensures the utility receives its intended base return on the investment.

As identified in Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report, Hydro Ottawa is proposing an earning sharing mechanism as part of the Non-Wires Customer Solutions program (NWCSP). As with the MoP, Hydro Ottawa has proposed this mechanism to be outside the traditional earning sharing mechanism.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-18

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / pp. 31-33 (pdf Exhibit 1 part 1, pp. 245-247)

QUESTION(S):

a) Why is Hydro Ottawa proposing a symmetrical NWS variance account, versus an asymmetrical variance account, if it plans to submit an application for any incremental solutions that fall outside of its approved funding?
b) How does Hydro Ottawa propose to handle changes in its capital budget if a non-wires solution is implemented which negates the need for a capital project contained in the application?

RESPONSE(S):

a) The proposed symmetrical variance account will account for approved funding variances within approved non wires solutions (NWS) projects. In Schedule 1-3-1, Hydro Ottawa maintains that for any incremental solutions (projects or programs) that fall outside of its approved NWS projects or program (i.e., new, significant NWS investments not covered by the current plan), Hydro Ottawa will submit a separate, comprehensive application for additional funding. This ensures transparency and OEB oversight for major new initiatives.

The symmetrical account is necessary to allow Hydro Ottawa to adapt and evolve its NWS program as it gains experience and as circumstances change over the rate term. This includes responding to factors beyond the utility's control, such as changes in the pace and type of DER uptake, shifts in demand-driven needs, and customer adoption rates. It is also unclear at this time how the IESO and local distribution companies will share costs to incent local initiatives

and therefore Hydro Ottawa was not able to accurately budget for the IESO portion and may need to incur a higher portion of the cost. By tracking both positive and negative variances from the approved budget, the symmetrical account provides a transparent mechanism to manage these changes effectively.

In addition to the proposed NWS Deferral Variance Account (DVA), Hydro Ottawa has proposed to maintain the Capital Variance Accounts (CVA) with modification. These mechanisms together have the ability to reallocate capital related cost to incremental operational costs and other revenue costs and funding associated with implementing approved NWS projects that effectively defer or avoid traditional capital expenditures.

b) If an incremental solution is approved and implemented during this Test period, thereby negating a planned capital project for the same period, any resulting underspending against the approved capital budget would be recorded in Hydro Ottawa's proposed Capital Variance Accounts (CVA).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-19

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / pp. 33-34 (pdf Exhibit 1 part 1, pp. 247-248)

QUESTION(S):

a) Hydro Ottawa is proposing a Large Load Variance Account to address “revenue uncertainty for load forecasting purposes”. Has Hydro Ottawa identified any precedence of use of load variance accounts by electricity distributors in Ontario?

RESPONSE(S):

a) This proposed revenue-focused variance account draws upon established regulatory precedents. For instance, it mirrors aspects of the Lost Revenue Adjustment Mechanism Variance Account (Account 1568), which tracks financial impacts from conservation programs. It also takes cues from the COVID-19 Foregone Revenues from Postponing Rate Implementation (Account 1509 Sub-Account), used for revenues lost when rate increases were delayed due to the pandemic. Lastly, it aligns with the Extended Horizons Variance Account (Account 1508 Sub-Account), which records the financial effects of reduced customer capital contributions due to longer connection and revenue horizons for housing developments, effective November 18, 2024.

This proposed account is intended to address "unique and unprecedented challenges" related to inherent uncertainty in forecasting individual customer's load, particularly in the early stages of the evolving energy landscape and decarbonization initiatives. This proposal aims to manage

revenue variances between forecast and actual billed demand for large load requests, accounting for both volume and timing variations.

While Hydro Ottawa has not had an opportunity to conduct a comprehensive review of other electricity distributor requests in Ontario during the timeframe allotted to respond to interrogatory responses, the utility believes that this request may be unprecedented at this time, given the number of large loads being introduced.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-20

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / Table 1 / p. 35 (pdf Exhibit 1 part 1, p. 249)

Preamble:
Per the OEB's Decision on Ontario Power Generation's Application for a variance account to capture the impact of the overturning of Bill 124, where a reasonable risk exists or should have been foreseeable the utility should address it as part of their rate application. As such Hydro Ottawa requests a deferral account to address the risk of tariffs from supply chain disruptions and tariffs on imported components essential for Hydro Ottawa's distribution infrastructure.

QUESTION(S):

a) How will "supply chain disruptions" be quantified in terms of dollars (CAD)?
b) Does Hydro Ottawa currently have an accounting system, or other mechanism, in place for quantifying supply chain disruptions in terms of dollars?

RESPONSE(S):

a) In the context of Hydro Ottawa's request for a deferral account to address tariff impacts, "supply chain disruptions" refer to interruptions or changes in the sourcing, transportation, or availability of materials, equipment, or services that are triggered by global tariff actions—including retaliatory tariffs, trade policy shifts, or border restrictions. These disruptions often result in increased costs for imported goods and services or the need to source alternative products at higher prices.

Quantifying these disruptions, in dollars, for the deferral account would involve tracking the incremental costs that can be directly attributed to the tariffs, distinguishing them from normal market fluctuations. This would primarily be achieved by:

- Itemized tariff charges on supplier invoices
- Documented price increases due to tariffs via contractual clauses, and supplier communications.

b) Yes, Hydro Ottawa currently has the ability to quantify supply chain disruptions and tariffs based on detailed supplier invoices and contract terms, comparing them against established baselines to isolate incremental costs. Accounts Payable and Procurement departments have the ability to track these costs separately within our existing financial systems.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-21

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 3 / pp. 4- 6 (pdf Exhibit 1 part 1, pp. 301-303)
Ref. 2: Exhibit 1 / Tab 3 / Schedule 3 / Attachment C / pp.12-16 (pdf Exhibit 1 part 1, pp. 386-390)

QUESTION(S):

a) Please reproduce Figure 6 and Figure 7 from reference 2, including data from Hydro Ottawa, peer group 1, and peer group 3, for 2013 through 2023.

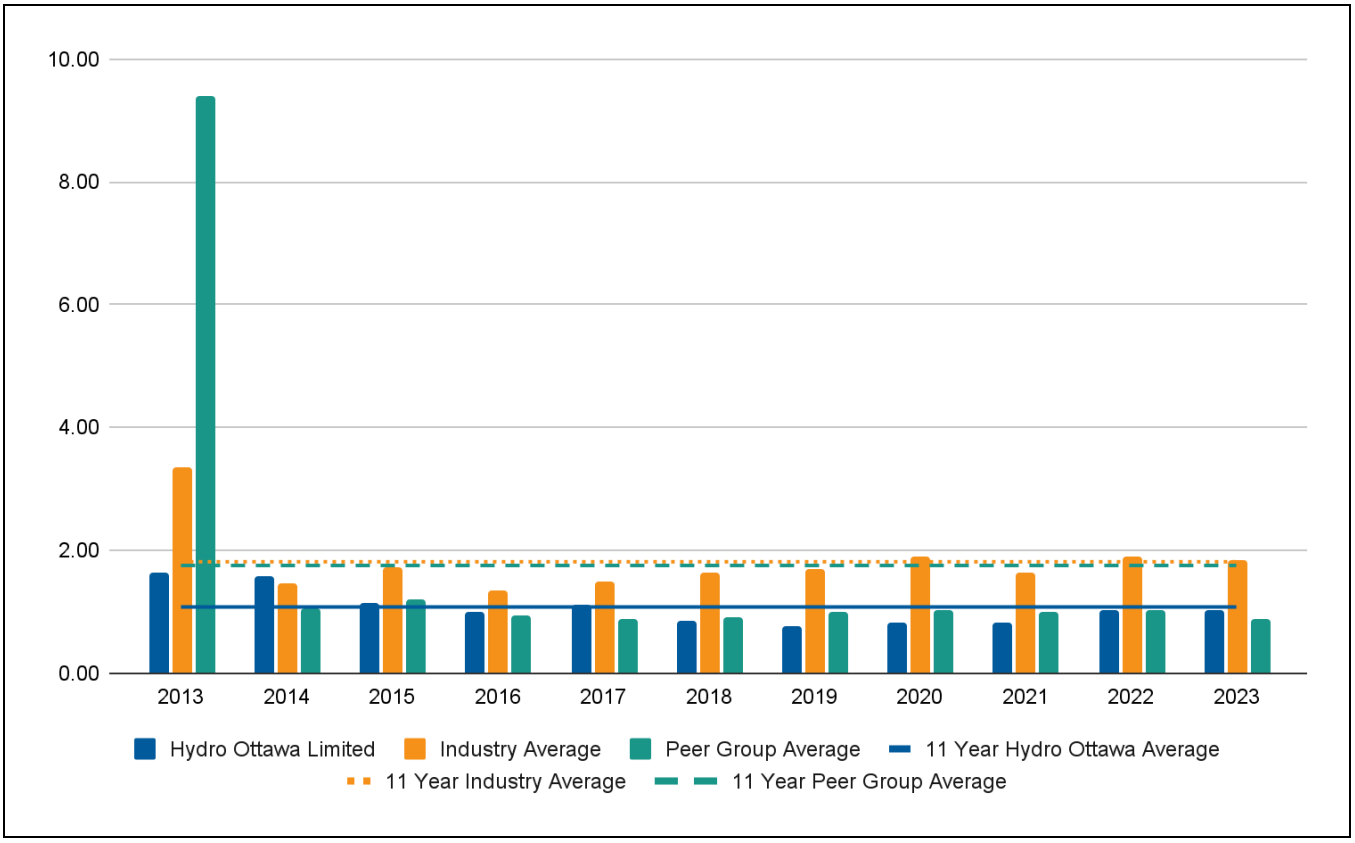
RESPONSE(S):

For the purposes of this response, Figure 6 and Figure 7 from Schedule 1-3-3(C) – Electricity Utility Scorecard Benchmarking Analysis – will be referred to as:

- Figure A for the Average Number of Hours that Power to a Customer is Interrupted using Peer Group 1.
- Figure B for the Average Number of Hours that Power to a Customer is Interrupted using Peer Group 3.
- Figure C for Average Number of Times that Power to a Customer is Interrupted using Peer Group 1.
- Figure D for Average Number of Times that Power to a Customer is Interrupted using Peer Group 3.

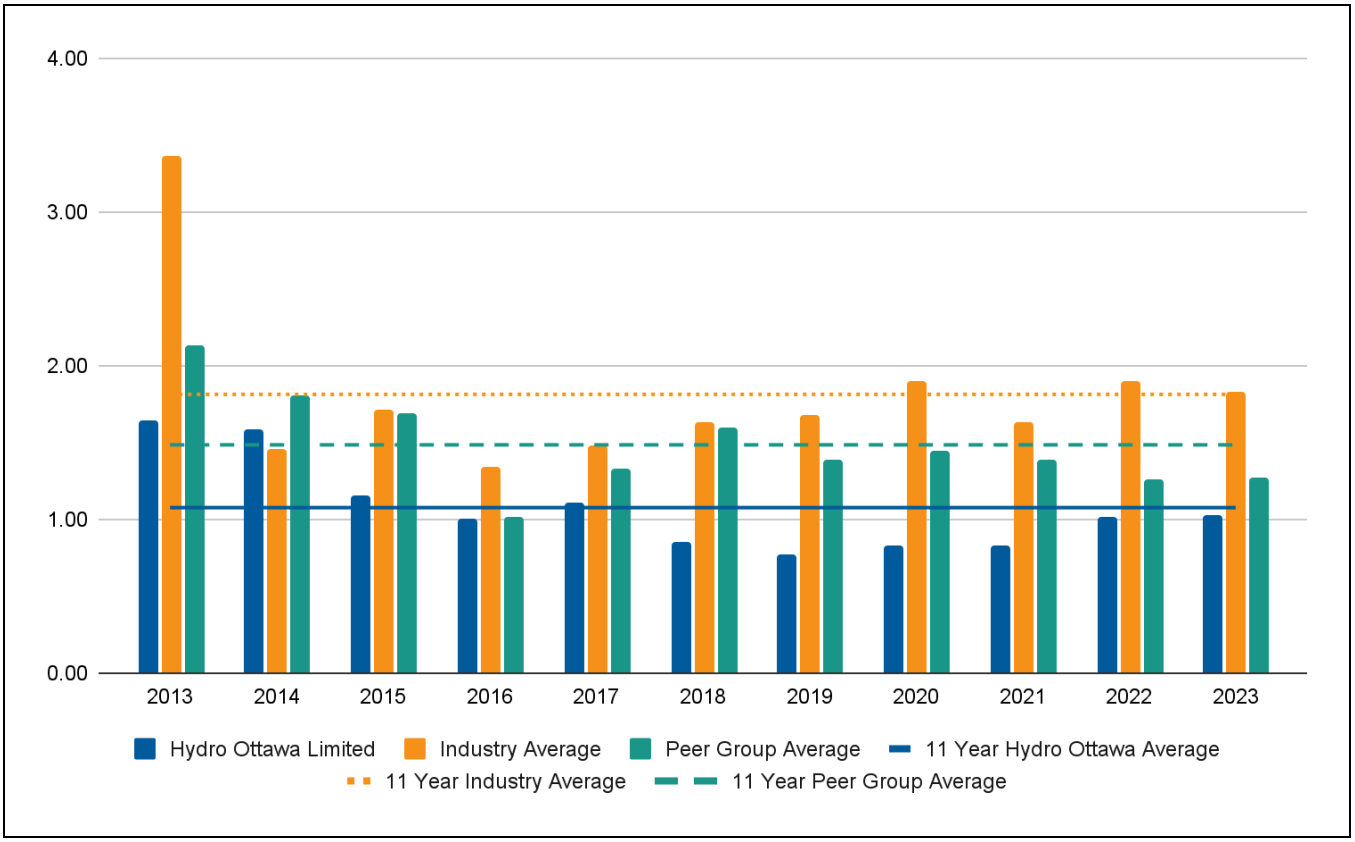
a) Please find below Figures 6 and 7 from Schedule 1-3-3(C) – Electricity Utility Scorecard Benchmarking Analysis. These figures have been reproduced as requested using data from Peer Group 1 and Peer Group 3 for the period 2013 to 2023, and are found below as Figures A, B, C and D.

Figure A - Average Number of Hours that Power to a Customer is Interrupted Industry and Peer Group 1* vs. Hydro Ottawa



*Elexicon Energy Inc. began reporting SAIDI and SAIFI in 2019. Enova Power Corporation began reporting SAIDI and SAIFI in 2022. Alectra Utilities Corporation began reporting SAIDI and SAIFI in 2017.

Figure B - Average Number of Hours that Power to a Customer is Interrupted Industry and Peer Group 3* vs. Hydro Ottawa



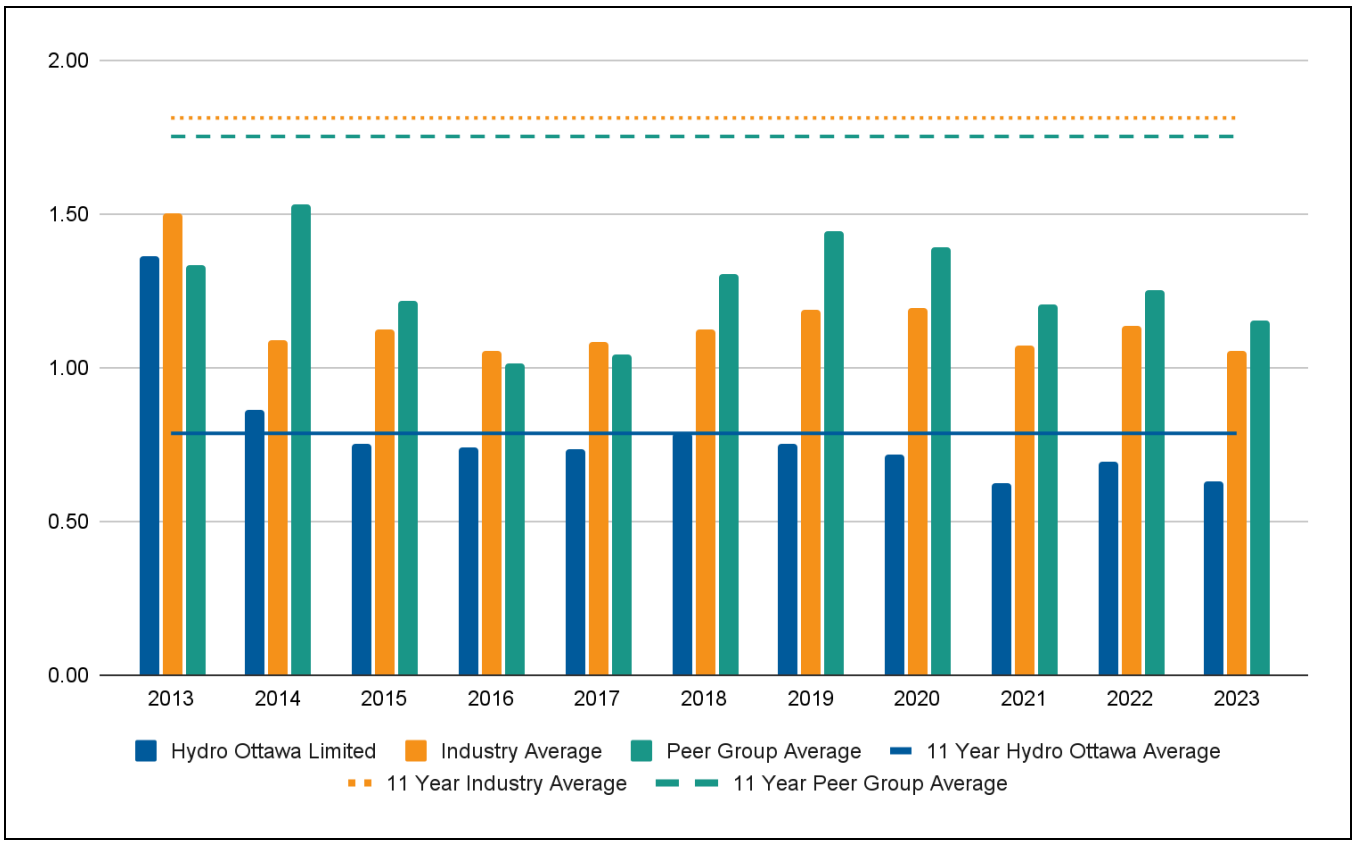
*Elexicon Energy Inc. and Synergy North Corporation began reporting SAIDI and SAIFI in 2019.

Figure C - Average Number of Times that Power to a Customer is Interrupted Industry and Peer Group 1* vs. Hydro Ottawa



*Elexicon Energy Inc. began reporting SAIDI and SAIFI in 2019. Enova Power Corporation began reporting SAIDI and SAIFI in 2022. Alectra Utilities Corporation began reporting SAIDI and SAIFI in 2017.

Figure D - Average Number of Times that Power to a Customer is Interrupted Industry and Peer Group 3* vs. Hydro Ottawa



*Elexicon Energy Inc. and Synergy North Corporation began reporting SAIDI and SAIFI in 2019.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-22

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 3 / Schedule 1 / Attachment A / Table 5 / pp.14-15 (pdf Exhibit 1 part 1, pp. 333-334)

Preamble:
With regard to the removal of costs associated with other revenues, Hydro Ottawa states the following:

> Hydro Ottawa therefore proposes to remove Other Revenues from the PEG Model's OM&A. Hydro Ottawa is using Other Revenues as a proxy for the costs associated with these auxiliary services.

Hydro Ottawa gives examples of move-ins and move-outs and its property rentals as part of the utility's auxiliary services.

QUESTION(S):

a) Please confirm if Hydro Ottawa is proposing to remove all items listed as Other Revenue included in Chapter 2 Appendices tab 2-H or specify which specific items it is proposing to remove.
b) Please provide an explanation to support the removal of each proposed item from OM&A.

RESPONSE(S):

a) Hydro Ottawa confirms that Uniform System of Accounts 4082 to 4420,[1] Other Revenue, listed in Attachment 6-3-1(A) - OEB Appendix 2-H - Other Revenue, are removed from the PEG model. The sum of those USoAs will reconcile with Attachment 1-3-3(G) - OEB Benchmarking Spreadsheet Forecast Model, tab "Model Inputs", cells H121 to N121, which are the annual totals of other revenue incorporated into the PEG model.

b) Hydro Ottawa provides its rationale for why Other Revenues should be removed from the PEG model in Section 4.3.1 Rationale of Attachment 1-3-3(A) - PEG Benchmarking Analysis.

Hydro Ottawa uses Other Revenue as a proxy for actual OM&A costs calculated by PEG, and removes them. The removal of these costs is necessary because these activities are not core distribution business functions; they are often driven by customer requests or inaction beyond the control of the utility, or the activity is provided to a third party outside of its distribution customer base.

Foremost, USoAs 2082 to 4420 are revenue offsets in the determination of Hydro Ottawa's base distribution charge, meaning that the utility charges separate fees for these services. In effect, these services are not core distribution business activities that warrant consideration in the PEG model.

As noted, these services are also often necessitated by customer requests or inaction. Late payment charges and frequent move-in, move-out requests (specific service charges) incur costs for the distributor that are recuperated through fees (other revenue). However, the demand for these services is largely beyond the control of Hydro Ottawa, limiting the potential for efficiencies. These costs are reported in the PEG model's actual OM&A.

[1] Excluding 4250 - Government and Other Assistance Directly Credited to Income for which Hydro Ottawa has not used.

Finally, activities such as rental fees provide a service to a third party, which incurs costs to Hydro Ottawa, which are subsequently reported in the PEG model's actual costs. In the case of rents, Hydro Ottawa does not operationally use the asset for distribution purposes, but it is charged with maintaining it to provide a service to the third party.

The revenues generated from all of these activities are a proxy for cost because it assumes that a rational actor, and also alignment with regulatory policy, would charge fees in a manner that covers its expenses for providing that service. Therefore, Other Revenues are removed from the PEG model's actual OM&A.

Please also note, through the adjustments of specific service charges, many of the costs have been provided in order to support the rate adjustments, please see Attachment 8-4-1(A) - Proposed and New Specific Service Charge Calculations and Attachment 8-4-2(A) - Proposed Generation Charge Calculations.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-23

EVIDENCE REFERENCE:

Benchmarking Results for Salary and Compensation
Ref. 1: Exhibit 1 / Tab 3 / Schedule 3 / Attachment F / pp. 5, 8-11 (pdf Exhibit 1 part 1, pp. 503, 506-509)

Preamble:
Reference 1 states that Mercer generally considers compensation to be competitive if it falls within +/-10% of the market median.

Mercer Canada's benchmarking results in reference 1 shows that some of the positions' base salary and target total cash compensation are notably higher than the market median (between 125% to 150%, which means 25% to 50% higher than the market median). These positions are System Designer, Warehouse Attendant, IT Service Desk Technician, Customer Contact Agent, Billing Service Associate, and Collection Agent.

QUESTION(S):

a) For the positions noted above, please provide the following information:
   i) An explanation why the total salary and compensation for each of these positions are much higher than the market median.
   ii) Please provide the number of employees per job title from 2021 to 2026.
   iii) Does Hydro Ottawa have any plans to re-align these positions to within 10% of the market median? Please explain.

RESPONSE(S):

a)

i) Compensation for the positions identified are governed by the collective agreement with IBEW Local 636. Hydro Ottawa has a long-standing bargaining relationship with this union, including the negotiation of across-the-board annual increases for the numerous positions covered by this collective agreement. During negotiations, Hydro Ottawa endeavors to ensure fair and equitable compensation that reflects industry standards and the geographic area of operation. The current compensation for these long-term positions, representing various sections of our business, is a result of compounded across-the-board annual wage increases and step progressions through the wage scale.

ii)

Table A - Number of FTEs Per Job Title, 2021-2026

	Historical								Budget			
	2021		2022		2023		2024		2025		2026	
Job Title	Full time	Part time	Full time	Part time	Full time	Part time	Full time	Part time	Full time	Part time	Full time	Part time
Billing Service Associate	10		9		8		11		9		9	
Collection Agent	7		5		3		5		6		6	
Customer Contact Agent	6		4		3		2		4		4	
IT Service Desk Technician	4		4		3	0.6	4	0.1	4		3	
System Designer	16		16	0.5	12	0.3	19	0.1	15		15	
Warehouse Attendant	8		7		6		6		7		7	
Total	**51**	**0**	**45**	**0.5**	**35**	**0.9**	**47**	**0.2**	**45**	**0**	**44**	**0**

iii) Hydro Ottawa does not have plans to re-align compensation for these positions as it was negotiated through collective bargaining. Though the market comparison study indicated these positions were above general industry comparators, they were either well aligned or slightly above utility market comparators.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-24

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 4 / Schedule 2 / Attachment A / p.17 (pdf Exhibit 1 part 2, p. 365)

QUESTION(S):

a) A table is provided that shows Social Permission by Residential Rate Class. Please provide the number of customers that were surveyed in each column, i.e., Residential Overall, LEAP Qualified, Income <$71k Not LEAP Qualified, Income>$71k Not LEAP Qualified and Prefer not to say.

RESPONSE(S):

a) The number of customers surveyed in each column on page 17 of Attachment 1-4-2(A) - Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application is as follows:

	Number of Customers Surveyed
Residential Overall	21,280
LEAP Qualified	3,593
Income <$71k, not LEAP Qualified	2,983
Income >$71k, not LEAP Qualified	10,330
Prefer not to say	4,374

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

1-Staff-25

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / HOL_Attachment 1-3-3(G) - OEB Benchmarking Spreadsheet Forecast Model_20250604.xlsx

QUESTION(S):

a) Sheet “Model Inputs” in reference 1 shows the inputs for the total cost benchmarking model used by Hydro Ottawa. For years 2024 to 2030, please explain how Delivery Volume (Required Item 4) and Annual Peak Demand (Required Item 5) are adjusted for the effects of CDM. Please provide supporting calculations and documentation.

RESPONSE(S):

a) Please refer to the response to interrogatory 1-Staff-11 and the associated Attachment 1-Staff-11(A) - CDM Supporting Data.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-26

EVIDENCE REFERENCE:

Ref. 1: Exhibit 1 / Tab 5 / Schedule 4 / Attachment A (pdf Exhibit 1 part 2, pp. 854-891)
Ref. 2: Attachment 9-3-1(A) / OEB Workform Deferral and Variance Account, April 28, 2025

QUESTION(S):

a) Please provide a reconciliation of the DVA balances in the DVA Continuity Schedule with the regulatory balances provided in Note 5 of Reference 1.

RESPONSE(S):

Preamble: Hydro Ottawa believes that Ref. 1, was intending to refer to Schedule 1, meaning, Exhibit 1 / Tab 5 / Schedule 1 / Attachment A (pdf Exhibit 1 part 2, pp. 854-891), which is Hydro Ottawa's Financial Statements for the year ending December 31, 2023. Further Hydro Ottawa believes that this reference only relates to Section 5 on pages 875-876, the Regulatory Balances of the Financial Statements, that contain DVA information. Ref. 2. Attachment 9-3-1(A) - OEB Workform Deferral and Variance Accounts was submitted on April 14, 2025.

a) Please see Tables A & B below for the reconciliations of the Financial Statements to the Regulatory Balances in Section 5 to the DVA Continuity Schedule for the years 2023 and 2022 respectively. In both tables the column, DVA Workform (Tab & Cell Reference), 2a., refers to tab 2a. Continuity Schedule and 2b., refers to tab 2b. Continuity Schedule. Notes in the tables explain details vs. the updated DVA Workform, refer to Attachment 1-Staff-1(C) - OEB_Workform - 2026 DVA_Continuity_Schedule, whereas notes below the tables explain details vs. the DVA Original Workform, referenced above.

Table A - Reconciliation of 2023 Financial Statements - Regulatory Balances to OEB DVA Workform ($'000s)

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2023	DVA Workform (Orig Submission)	DVA Workform (Tab & Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
Regulatory debit balances									
RARA	1595	$ 8,941	$ 8,941	$ 7,664	2a. BG36:BG39 + BL36:BL39	$ 7,664	2a. AW35:AW38 + BB35:BB38	$ -	USofA 1595, the net of, the debit of $8,941k and credit of $1,277k sum to $7,664k in the DVA Workform Column
Settlement variances	1550	$ 57	$ 36,124	$ 57	2a. BG24 + BL24	$ 57	2a. AW24 + BB24	$ -	
	1580	$ 6,759		$ 6,104	2a. BG25 + BL25 + BG28 + BL28	$ 6,104	2a. AW26+ BB26 + AW28 + BB28	$ 1	USofA 1580, the net of, the debit of $6,759k and credit of $656k sum to $6,104k in the DVA Workform Column
	1584	$ 13,031		$ 13,031	2a. BG29 + BL29	$ 13,031	2a. AW29 + BB29	$ -	
	1588	$ 9,258		$ 2,932	2a. BG31 + BL31	$ 2,932	2a. AW31 + BB31	$ (6,326)	$6,327k - 2023 Principal Adjustment from Attachment 9-3-1 (B) - OEB Workform - Global Adjustment Analysis cell V62
	1589	$ 7,019		$ 6,424	2a. BG32 + BL32	$ 6,424	2a. AW32 + BB32	$ (595)	$595k - 2023 2023 Principal Adjustment from Attachment 9-3-1 (B) - OEB Workform - Global Adjustment Analysis cell J62

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2023	DVA Workform (Orig Submission)	DVA Workform (Tab & Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
OPEB cash versus accrual	1508	$ 3,532	$ 3,532	$ 3,532	2b. BG59	$ 3,532	2b. AW59	$ -	
Regulatory asset for deferred income taxes	2350	$ 82,622	$ 82,622	n/a					
Other variances and deferred costs	1508	$ 925	$ 623	$ 925	2b. BG71	$ 925	2b. AW71	$ -	
	1508	$ 510		$ 510	2b. BG68 + BL68	$ 510	2b. AW68 + BB68	$ -	
	1508	$ 50		$ 50	2b. BG69 + BL69	$ 50	2b. AW69 + BB69	$ -	
	1508	$ 2		$ 2	2b. BG70 + BL70	$ 2	2b. AW70 + BB70	$ -	
	1508	$ 741		$ 741	2b. BG49 + BL49	$ 741	2b. AW49 + BB49	$ -	
	1508	$ 738		$ 738	2b. BG56 + BL56	$ 738	2b. AW56 + BB56	$ -	
	1508	$ (2,343)		n/a					
TOTAL REGULATORY DEBIT BALANCES			**$ 131,842**						

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2023	DVA Workform (Orig Submission)	DVA Workform (Tab & Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
Regulatory credit balances									
RLRA	1595	$ 1,277	$ 1,277		2a. BG36:BG39 + BL36:BL39				USofA 1595 - The net of, the debit of $8,941k and credit of $1,277k sum to $7,664k in the DVA Workform Column
Settlement variances	1551	$ 1,764		$ 1,764	2a. BG25 + BL25	$ 1,764	2a. AW25 + BB25	$ -	
	1580	$ 656			2a. BG25 + BL25 + BG28 + BL28				USofA 1580 - The net of, the debit of $6,759k and credit of $656k sum to $6,104k in the DVA Workform Column
	1586	$ 2,423	$ 4,843	$ 2,423	2a. BG30 + BL30	$ 2,423	2a. AW30 + BB30	$ -	
ESM	1508	$ 1,540	$ 1,540	$ 1,254	2b. BG65 + BL65	$ 1,540	2b. AW65 + BB65	$ 0	
Gain on asset disposal	1508	$ 1,093	$ 1,093	$ 1,093	2b. BG64 + BL64	$ 1,093	2b. AW64 + BB64	$ 0	
LRAM	1568	$ 3,055	$ 3,055	$ 634	2b. BG91 + BL91	$ 3,055	2b. AW91 + BB91	$ (0)	

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2023	DVA Workform (Orig Submission)	DVA Workform (Tab & Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
OPEB deferral account	1522	$ 62	$ 62	$ 99	2b. BG75 + BL75	$ 62	2b. AW75 + BB75	$ 0	
Other variances and deferred costs	1508	$ 570	$ 3,089	561	2b. BG66 + BL66	570	2b. AW66 + BB66	$ 0	
	1508	$ 317		317	2b. BG67 + BL67	317	2b. AW67 + BB67	-	
	1508	$ 530		571	2b. BG73 + BL73	531	2b. AW73 + BB73	$ 1	Rounding
	1508	$ 820		820	2b. BG72 + BL72	820	2b. AW72 + BB72	-	
	1592	$ 852		854	2b. BG86 + BL86	852	2b.AWG86 + BB86	$ (0)	
TOTAL REGULATORY CREDIT BALANCES			**$ 14,959**						

1

Notes for Table A (2023 reconciliation):

- Please refer to Attachment 9-3-1(A) - OEB Workform Deferral and Variance Accounts (Continuity Schedule) that was submitted on April 15, 2025 for DVA Workform tab and cell references outlined in notes for Table A.
- Totals may not sum due to rounding.
- In USofA Description column, all 1508 accounts are Sub-Accounts.
- In the USofA Amount column, USofA 1595, the net of, the debit of $8,941k and credit of $1,277k sum to $7,664k in the DVA Workform Column.
- In the USofA Amount column, USofA 1580, the net of, the debit of $6,759k and credit of $656k sum to $6,104k in the DVA Workform Column.
- In the USofA Amount column, USofA 1588, the difference between the USofA amount of $9,260k and $2,932k of $6,328k is due to true-up adjustments amounts recorded in 2024, please refer to Tab 3. Appendix A cells E31 & F31.
- In the USofA Amount column, USofA 1589, the difference between the USofA amount of $7,019k and $6,424k of $595k is due to true-up adjustments amounts recorded in 2024, please refer to Tab 3. Appendix A cells E32 & F32.
- In the USofA Column, USofA 1508 Sub-Account - ESM, the difference between the USofA Amount of $1,540k and the DVA Workform of $1,254k of $286k is a result of prior year adjustments booked in 2023, please refer to 2b. Continuity Schedule cells BF65 + BK65.
- In the USofA Column, USofA 1568 Sub-Account - LRAM, the difference between the USofA Amount of $3,055k and the DVA Workform of $634k of $2,421k is a result of prior year adjustments and opening principle balance booked in 2023, please refer to 2b. Continuity Schedule cells BC91 + BF91 + BK91.
- In the USofA Column, USofA 1522, the difference between the USofA Amount of $62k and the DVA Workform of $99k of $37k is a result of prior year adjustments booked in 2023, please refer to 2b. Continuity Schedule cell BK75.
- In the USofA Column, USofA 1508 Sub-Account - CCRA, the difference between the USofA Amount of $570k and the DVA Workform of $561k of $9k is a result of prior year adjustments booked in 2023, please refer to 2b. Continuity Schedule cells BF66 + BK66 .

- In the USofA Column, USofA 1508 Sub-Account - CVA Variance, the difference between the USofA Amount of $530k and the DVA Workform of $571k of $41k is a result of prior year adjustments booked in 2023, please refer to 2b. Continuity Schedule cells BF73 + BK73.
- USofA's 2350 - Deferred Income Tax Asset - Reclass and 1508 - Sub-Account - Regulatory Provisions are used for Financial Statement purposes but are not included in the DVA Workform and have been indicated with n/a in the DVA Workform column of the Table.

Table B - Reconciliation of 2022 Financial Statements - Regulatory Balances to OEB DVA Workform ($'000s)

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2022	DVA Workform	DVA Workform (Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
Regulatory debit balances									
RARA	1595	$ 687	$ 687	$ (472)	2a. AW35:AW38 + BB35:BB38				
Settlement variances	1580	$ 18,371	$ 36,723	$ 16,418	2a. AW26 + BB26 + AW28 + BB28				
	1584	$ 14,485		$ 14,485	2a. AW29 + BB29				
	1588	$ 3,867		$ 2,126	2a. AW31 + BB31				
OPEB cash versus accrual	1508	$ 3,218	$ 3,218	$ 3,218	2b. AW59	$ 3,218	2b. AM59	$ (0)	
Loss on asset disposal	1508	$ 148	$ 148	$ 148	2b. AW64 + BB64	$ 148	2b. AM64 + AR64	$ 0	
Regulatory asset for deferred income taxes	2350	$ 74,239	$ 74,239	n/a					

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2022	DVA Workform	DVA Workform (Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
Other variances and deferred costs	1508	$ 1,387	$ 1,498	$ 1,387	2b. AW71	$ 1,387	2b. AM71	$ 0	
	1508	$ 485		$ 486	2b. AW68 + BB68	$ 486	2b. AM68 + AR68	$ 1	Rounding
	1508	$ 48		$ 48	2b. AW69 + BB69	$ 48	2b. AM69 + AR69	$ (0)	
	1508	$ 2		$ 2	2b. AW70 + BB70	$ 2	2b. AM70 + AR70	$ (0)	
	1592	$ 62		$ 62	2b. AW85	$ 644	2b. AM85	$ 582	Principal Adjustment $634k Interest Adjustment $(52k)
	1508	$ 706		$ 706	2b. AW49 + BB49	$ 706	2b. AM49 + AR49	$ (0)	
	1508	$ (1,192)		n/a					
TOTAL REGULATORY DEBIT BALANCES			**$ 116,513**						

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2022	DVA Workform	DVA Workform (Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
Regulatory credit balances									
RLRA	1595	$ 1,148	$ 1,148						
Settlement variances	1550	$ 345	$ 17,034	$ 345	2a. AW24 + BB24				
	1551	$ 1,243		$ 1,243	2a. AW25 + BB25				
	1580	$ 1,953			2a. AW26 + BB26 + AW28 + BB28				
	1589	$ 9,136		$ 9,201	2a. AW32 + BB32				
	1586	$ 4,357		$ 4,357	2a. AW30 + BB30				
ESM	1508	$ 1,467	$ 1,467	$ 1,467	2b. AW65 + BB65	$ 1,196	2b. AM65 + AR65	$ (271)	Principal Adjustment $(312k), Interest Adjustment $41k
LRAM	1568	$ 103	$ 103	$ 103	2b. AW91 + BB91	$ 1,241	2b. AM91 + AR91	$ 1,138	Principal Adjustment $758k, Interest Adjustment $380k

Financial Statement Description	USofA Acct	USofA Amount	Financial Statements 2022	DVA Workform	DVA Workform (Cell Reference)	DVA Workform (1-Staff-1)	DVA Workform (Tab & Cell Reference)	DVA vs. F/S - Check	Notes
OPEB deferral account	1522	$ 30	$ 30	30	2b. AW75 + BB75	$ 46	2b. AM75 + AR75	$ 16	Interest Adjustment $(16k)
Other variances and deferred costs	1508	$ 657	$ 1,904	657	2b. AW66 + BB66	$ 273	2b. AM66 + AR66	$ (384)	Principal Adjustment $(368k), Interest Adjustment $(16k)
	1508	$ 302		302	2b. AW67 + BB67	302	2b. AM67 + AR67	$ (0)	
	1508	$ 545		545	2b. AW73 + BB73	582	2b. AM73 + AR73	$ 37	Principal Adjustment $64k Interest Adjustment $(27k)
	1508	$ 400		400	2b. AW72 + AW72	400	2b. AM72 + AR72	$ -	
TOTAL REGULATORY CREDIT BALANCES			**$ 21,686**						

1

Notes for Table B (2022 reconciliation):

- Please refer to Update Dec 13-23_OEB WF Deferral and Variance Account (Continuity Schedule)[1] for DVA Workform tab and cell references outlined in notes for Table B.
- Totals may not sum due to rounding.
- In USofA Description column, all 1508 accounts are Sub-Accounts.
- In the USofA Amount column, USofA 1595, the net of, the debit of $687k and credit of $1,148k sum to $(472k) in the DVA Workform Column.
- In the USofA Amount column, USofA 1580, the net of, the debit of $18,371k and credit of $1,148k sum to $16,418k in the DVA Workform Column.
- In the USofA Amount column, USofA 1588, the difference between the USofA amount of $3,867k and $2,126k of $1,741k is due to true-up adjustments amounts recorded in 2023, please refer to Tab 3. Appendix A cells E31 & F31.
- In the USofA Amount column, USofA 1589, the difference between the USofA amount of $9,136k and $9,201k of $65k is due to true-up adjustments amounts recorded in 2023, please refer to Tab 3. Appendix A cells E32 & F32.
- USofA's 2350 - Deferred Income Tax Asset - Reclass and 1508 - Sub-Account - Regulatory Provisions are used for Financial Statement purposes but are not included in the DVA Workform and have been indicated with n/a in the DVA Workform column of the Table.

[1] Hydro Ottawa, *Update Dec 13-23_OEB WF Deferral and Variance Account Continuity Schedule*, EB-2023-0032, (December 13, 2023).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-27

EVIDENCE REFERENCE:

Ref. 1: Attachment 2-2-1(A)/ OEB Appendix 2-BA 2021-2025 Fixed Asset Continuity Schedule, June 6, 2025
Ref. 2: Attachment 2-2-1(B)/ 2030 Fixed Asset Continuity Schedule, April 15, 2025
Ref. 3: OEB Accounting Procedures Handbook for Electricity Distributors, January 1, 2012
Ref. 4: Attachment 6-3-1(A)/ OEB Appendix 2-H Other Revenue, April 15, 2025

Preamble:
Page 102 of Reference 3 states that amounts recognized in Account 2440, Deferred Revenue, should be amortized to income over the useful life of the related property, plant and equipment by debiting this account and crediting Account 4245.

In Reference 4, OEB staff notes that there are no amounts reported in Account 4245, Government and Other Assistance Directly Credited to Income for the historic years or the test years.

QUESTION(S):

a) Please update References 1 and 2 to ensure that the depreciation for the deferred revenue is excluded from the net depreciation amount.
b) Please update Reference 4 to ensure the depreciation for the deferred revenue is captured in Account 4245 for the historic years and the test years.
c) Please update the revenue requirement workforms for test years 2026-2030 accordingly to reflect the changes made in a) and b).

RESPONSE(S):

a) Please see the following attachments that include the requested revisions updated based on the Appendices submitted on June 4, 2025. Please note that Ref 2 of the question only refers to the 2030 Fixed Asset Continuity Schedule, however all years from 2026-2030 have been provided.

- Attachment 2-Staff-27(A) - Updated Appendix 2-BA 2021-2025 Fixed Asset Continuity Schedule, Submitted June 6, 2025
- Attachment 2-Staff-27(B) - Updated Appendix 2-BA 2026-2030 Fixed Asset Continuity Schedule, Submitted April 15, 2025

b) Please see Attachment 2-Staff-27(C) - Updated Attachment 6-3-1(A) - OEB Appendix 2-H Other Revenue, Submitted April 15, 2025, which includes the requested revisions.

c) In the context of ratemaking, the amortization of capital contributions reported in Account 4245 is an offset to assets and therefore netted against rate base.

> "Records shall be maintained so that the contribution or grant can be directly assigned to specific type of asset for which the contribution was made to ensure the proper offset is made to the asset before inclusion in rate base as prescribed in Article 430 Contributions in Aid of Construction."[1,2]

As a result, Hydro Ottawa has not had to update its revenue requirement file for the purpose of this interrogatory response.

Please refer to interrogatory response 1-Staff-1 for updated revenue requirement workforms for test years 2026-2030, which reflect other interrogatory responses and 2024 Actual amounts. The workforms provided therein for the test years 2026-2030 incorporate all the necessary

[1] Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors*, (December 2011, effective January 1, 2012), page 102.
[2] Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors, Article 430*, (December 2011, effective January 1, 2012), page 7.

adjustments and calculations, including the standard treatment of capital contributions for ratemaking purposes.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-28

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / HOL_Attachment 2-5-5(A) - OEB Appendix 2-AA -Capital Programs Table_20250604.xlsx
Ref. 2: Exhibit 2 / HOL_Attachment 2-5-5(B) - OEB Appendix 2-AB - Capital Expenditure Summary_20250415.xlsx
Ref. 3: Exhibit 2 / Tab 5 / Schedule 5 / p. 105 (pdf Exhibit 2 part 4, p. 105)
Ref. 4: Exhibit 2 / Tab 5 / Schedule 9 / pp. 81, 102, 117 (pdf Exhibit 2 part 4, pp. 659, 680, 695)

Preamble:
Capital contributions in the general plant budget category are shown as a row in Appendix 2-AA. Exhibit 2-5-5, Table 35, contains general plant contribution values for the historic and forecast period that reconcile with the amounts within Appendix 2-AA.

OEB staff have identified three general plant programs that contain capital contributions, but the total of these programs does not reconcile with the amounts shown in Appendix 2-AA, particularly for 2026 and 2027. OEB staff are not interested in the immaterial differences in other years that may be the result of rounding.

Table: General Plant Capital Contributions by Program ($M)

		Historical Years			Bridge Years		Test Years				
Table		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
26	Infrastructure and Cyber Security	0.50	0.20	0.40	1.10	1.00	0.60	0.80	0.90	0.70	0.50
33	Facilities Programs	0	0	0.20	0.10	0	0	0	0	0	0
40	Fleet Replacement Program	0	0	0.10	0	0	0	0	0	0	0
	Total	**0.50**	**0.20**	**0.70**	**1.20**	**1.00**	**0.60**	**0.80**	**0.90**	**0.70**	**0.50**
	Total From 2-AA	0.46	0.18	0.74	1.24	0.96	5.64	4.94	0.86	0.70	0.50
	Difference	0.04	0.02	0.04	0.04	0.04	**5.04**	**4.14**	0.04	0.01	0.00

QUESTION(S):

a) Please validate or correct the information in the table above constructed by OEB staff from Exhibit 2.
b) What is the source of the contributions in the Infrastructure and Cyber Security Program?
c) Please identify all general plant programs that contain contributions, quantify the contributions, and explain the source of the contributions.

RESPONSE(S):

a) The values in the table are correct. As OEB staff have noted, immaterial differences do exist in all years due to rounding except for 2026 and 2027. The driver of the large variances in 2026 and 2027 relate to payment in lieu of taxes (PILS) capital contributions. The amounts budgeted

for 2026 and 2027 are $5.07M and $4.1M respectively. Hydro Ottawa is proposing to exclude the impact of the decrease in Grossed Up PILS due to Accelerated CCA for 2026 and 2027 and the impact in the decrease in accumulated Grossed Up PILS due to the 2021 immediate expensing measure in the proposed revenue requirement for 2026 and 2027. Further detail can be found in Section 7 of Schedule 9-1-4 - Account 1592 PILS and Tax Variance. There are no capital expenditures budgeted against this program in any year which is why it is not shown in Schedule 2-5-9 - General Plant Investments.

b) The contributions that are attributable to the Infrastructure and Cybersecurity program are Scientific Research and Experimental Development (SR&ED) tax credits. Hydro Ottawa engages its external auditor on an annual basis to determine eligible initiatives to include in its annual SR&ED claim; the majority of the projects identified for inclusion in the claim fall under the Infrastructure and Cyber Security program.

c) The table above contains all the general plant programs that contain contributions, and as noted in the response to part a), the amounts by program are correct.

The sources of contributions by program are as follows:

- Infrastructure and Cyber Security: the source of the contributions in all years are SR&ED tax credits.
- Facilities Programs: the source of the contributions in 2023 and 2024 are grant funding received from Natural Resources Canada (NRCan) for the installation of Electric Vehicle (EV) charging stations at Hydro Ottawa's facilities, as noted in Section 10.5 of Schedule 2-5-9 - General Plant Investments.
- Fleet Replacement Program: the source of contributions in 2023 are federal government rebates under the Incentives for Medium and Heavy Duty Zero-Emission Vehicles (iMHZEV) program for EV purchases, as noted in Section 11.5 of Schedule 2-5-9 - General Plant Investments.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-29

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 1 / Schedule 1 / pp. 6-8 (pdf Exhibit 2 part 1, pp. 6-8)

Preamble:
When discussing the major drivers of the higher in-service additions, Increased Emergency Renewal Work due to Major Storm Equipment Failure was listed. This point highlights the 2022 Derecho which left significant damage to equipment including poles.

QUESTION(S):

a) Were pole failures significantly correlated with the condition of the poles that failed prior to onset of the Derecho?
b) If pole condition prior to onset of the Derecho was a material factor in the pole failures, does this mean that the 500 poles replaced following the Derecho augmented the 2022 pole replacement program by triggering the replacement of poor condition poles? Please discuss.
c) If pole condition prior to the onset of the Derecho was not a material factor in the pole failures, does this indicate that pole condition is not a critical risk factor, since even poles in poor condition survived the Derecho, while poles that were in good condition did not survive. Please discuss.

RESPONSE(S):

a) Hydro Ottawa has analyzed the condition profile of the poles that failed prior to the onset of the Derecho event; the summary is presented in Table A.

Table A - Condition Assessment of Poles impacted by Derecho Event

Condition	Number of Poles
Very Poor	211
Poor	5
Fair	60
Good	20
Very Good	46
No Data/Invalid	68
Total Number of Poles	**410**

Hydro Ottawa's asset condition assessment process and the definition of the aforementioned condition ranges is provided in Section 5.1.2.1 Asset Condition Assessment under Schedule 2-5-4 - Asset Management Process. 52% of the poles impacted by the Derecho event were in a Very Poor/Poor condition, but 31% of the poles that failed were in an acceptable condition, with the condition profile of the remaining 17% not being determined, due to the absence of condition data. The poles under the No Data/Invalid category were on the schedule for being inspected as a part of Hydro Ottawa's 10-year pole inspection cycle. Pole failures in extreme weather are typically caused by a combination of factors.

b) Hydro Ottawa made strategic adjustments to mitigate overall capital cost overruns in the Pole Renewal Program, following the unanticipated Derecho event, as explained in Hydro Ottawa's response to interrogatory 2-Staff-32 part a) ii).

c) Pole failures during extreme weather events stem from a confluence of factors, not solely the pole's condition (though pole condition is definitely a consideration). As elaborated in CSA 22.3 No. 1: Overhead Systems and Hydro Ottawa's response to interrogatory 2-Staff-36 part a) iii), a pole's resilience to severe weather is significantly impacted by various critical elements and not solely confined to condition.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-30

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 1 / Schedule 1 / p. 10 (pdf Exhibit 2 part 1, p. 10)

Preamble:
Table 5 – Variances in Net In-Service Capital Additions - System Access ($'000s) provides a breakdown of the OEB Approved spending, the Historical/Bridge spending and the variance for the Capital Programs.

QUESTION(S):

a) Please confirm if the Plant Relocation is primarily driven by road moves and widening requested by the road authority. If not, please discuss.
b) Please provide more details on what is included in the Customer Connection and what drove the 73% variance.

RESPONSE(S):

a) Yes, Hydro Ottawa's plant relocation initiatives are primarily driven by road moves and widening projects requested by various authorities and third-party agencies. These include the Ministry of Transportation of Ontario (MTO), the City of Ottawa, the Municipality of Casselman, and the National Capital Commission (NCC). Specifically, Hydro Ottawa's Plant Relocation and Upgrade Program directly stems from planned road widening projects identified in the City of Ottawa's Transportation Master Plan as part of the "Affordable Road Network Initiative." Examples include the widening of Bank Street and Prince of Wales Drive (from two to four lanes) and the planned road extension of Preston Street.

Under the Public Service Work on Highways Act (PSWHA), Hydro Ottawa is mandated to work with public entities requesting infrastructure relocations and respond in a timely manner to facilitate the maintenance and improvement of public infrastructure.

b) An overview of the programs in Customer Connections is provided in Section 3.1 of Schedule 2-5-6 - System Access Investments. The included programs are:

- Residential Subdivisions
- Commercial Developments
- Infill (Residential & Small Commercial)

Please refer to Section 5.1.2. Historical Variances section of Schedule 2-5-5 - Capital Expenditure Plan for drivers of the variances in Customer Connections In-Service Capital Additions. The most notable factors described in Section 5.1.2 and driving variances in capital expenditures and consequently, in service additions were:

- City of Ottawa's Intensification Policies & Provincial Housing Mandates
- COVID-19 Pandemic
- LRT Phase II Project Delays
- Inflationary Pressures
- External Project Dependencies

Please note that capital expenditure variances are directly tied to in-service capital additions variances, though the spending and energization might occur in different calendar years based on specific project start and completion dates. For more details surrounding year over year in-service addition variances please refer to Section 4 of Schedule 2-1-1 - Rate Base Overview for year over year in-service capital additions variances by Investment Category.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-31

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 1 / Schedule 1 / p. 12 (pdf Exhibit 2 part 1, p. 12)

Preamble:
Table 7 highlights the capital additions related to System Renewal over the 2021-2025 Test period.

QUESTION(S):

a) What percentage of the assets replaced under the corrective renewal line item were already scheduled for replacement during the 2021-2025 test period?
b) What percentage of assets replaced during 2021-2025 would have been scheduled for replacement during the upcoming test period?

RESPONSE(S):

Hydro Ottawa notes that the preamble should state “Table 7 highlights the variances in net in-service capital additions related to System Renewal over the 2021-2025 historical/bridge period”.

a) The Corrective Renewal program is broken down into 3 budget programs: Damage to Plant, Emergency Renewal and Critical Renewal, as outlined in Table 11 of Schedule 2-5-4- Asset Management Process.

   The Damage to Plant program includes the replacement of assets that have failed due to damage caused by third parties, as described in Section 6.1 on page 154 of Schedule 2-5-4 - Asset Renewal Investments. It is possible that the assets replaced under emergency would

have been planned for replacement during the historic/bridge period or the upcoming test period; however, Hydro Ottawa does not track the asset level details to provide the specific count.

The assets replaced under the Emergency Renewal budget program have failed and resulted in an outage or have been found to pose a definite and immediate safety or environmental risk, as described in the underlying considerations for the Emergency budget program in Table 25 under Section 6.1: Program Summary of Schedule 2-5-7: System Renewal Investments. It is possible that the assets replaced under the Emergency budget program would have been planned for replacement during the historic/bridge period or the upcoming test period; however, Hydro Ottawa does not track the asset level details to provide the specific count.

The assets replaced under the Critical Renewal budget program are deemed to have functionally failed, as described in the underlying considerations in Table 26 under Section 6.1: Program Summary of Schedule 2-5-7: System Renewal Investments. It is highly likely that the assets under this program would have been planned for replacement during the historic/bridge period and, if not, during the upcoming test period, as they would very likely have had a health index score of poor or very poor; however, Hydro Ottawa does not track the asset level details to provide the specific count.

b) Please see the response to (a).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-32

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 1 / Schedule 1 / pp. 12-14 (pdf Exhibit 2 part 1, pp. 12-14)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 3 / p. 56 (pdf Exhibit 2 part 2, p. 218)

Preamble:
Table 26 from reference 2 shows the trend in pole failure from 2019-2023, with a maximum shown in 2022 with 8 poles.

Hydro Ottawa provides a detailed analysis of the remaining $11.2 million overage in System Renewal in-service capital additions for the 2021-2025 test period below.

- Overhead Distribution Asset Renewal: Despite overages in Planned Pole Renewal and System Renewal overall, active deferrals in Insulator Replacement and Overhead Switch programs are projected to keep capital additions $2.0M below the approved amount.
- Corrective Renewal (excluding the $16.1M storm costs discussed above): The Emergency Renewal program experienced higher than OEB-Approved capital additions of approximately $12.5M related to distribution transformers. Hydro Ottawa observed a general trend/issue with leaking transformers related to a specific manufacturer and certain localized regions […]
- Metering Renewal: Bridge and Test Year capital additions for the Metering Renewal program are expected to be below OEB-Approved amounts by $1.4M; driven by persistent delays in acquiring Gatekeeper meters that were part of the Self-Contained Meter Phone Line Elimination project. Consequently, in 2024 the Gatekeeper solution was deemed unsuccessful, which resulted in the reduction of the Metering Renewal program in 2024 and 2025 […]

QUESTION(S):

a) Please confirm that more poles were replaced than was planned under this program during the historical/bridge period, and that an additional 500 poles were replaced as a result of the 2022 Derecho.
   i) If confirmed, discuss whether this means that Hydro Ottawa can moderate its pole replacement program during the upcoming test period, given that significantly more poles were replaced than was planned during the prior test period.
   ii) If not confirmed, please explain why not.

b) Please break down the $12.5M in unapproved incremental distribution transformer emergency replacements into separate line items for each significant trigger factor, e.g., rapid onset leaks due to transformer manufacturer deficiency, lightning strikes or surges, foreign contact (trees, vehicles, etc.) and all other individually significant trigger factors.

c) Does the trend/issue identified with transformers indicate a type of fault with the affected transformers, or are the leaks due to inappropriate installation, maintenance or operational practices?
   i) If these are a type of fault, does Hydro Ottawa have recourse against the faulty transformer manufacturer? Please discuss.

d) Please explain why the Gatekeeper solution was deemed unsuccessful.

e) Quantify the total spend on the attempted Gatekeeper solution implementation, by year.
   i) What was the amount capitalized for the Gatekeeper meter project per year? Will the installed Gatekeeper meters be used or replaced? If replaced, what will be the accounting treatment of the assets?

RESPONSE(S):

a) This is not confirmed.
   i) Not applicable.
   ii) Hydro Ottawa did not replace more poles than was planned under this program during the historical/bridge period. Hydro Ottawa initially planned to replace 2,000 poles under this program and will instead replace 1,732 poles, per Table 10 of Section 3.5 in Schedule 2-5-7 - System Renewal Investments. Separately, Hydro Ottawa would like to

clarify that the utility replaced 400 poles, not 500 poles, as a result of the 2022 Derecho, as shown in Hydro Ottawa's response to part (a) of interrogatory 2-Staff-29. Importantly, the poles replaced during the Derecho were part of the Corrective Renewal (Emergency Renewal) program and not included in the Planned Pole Renewal metrics. The adjustment to the planned pole renewal program was made solely to mitigate overall capital cost overruns. Please refer to Section 4.1.1 and Section 4.1.3.4 of Schedule 2-5-5 - Capital Expenditure Plan for more information.

b) Table A breaks down the $15.2M of 2021-2025 Historical/Bridge spending into separate line items for each significant trigger factor that is resulting in the $12.5M in incremental distribution transformer emergency replacements. Please note that 2024-2025 spending was categorized as "Other" as these are projected expenditures based on historical trends.

Table A – 2021-2025 Historical/Bridge Years Spending of Emergency Underground Transformers by Cause ($'000s)

Cause	Historical Years	Bridge Years	Total
	2021-2023	2024-2025	2021-2025
Adverse Weather	$ 7	-	$ 7
Electrical Failure	$ 916	-	$ 916
Foreign Interference	$ 8	-	$ 8
Mechanical Failure	$ 347	-	$ 347
Oil Leak	$ 7,719	-	$ 7,719
Other	$ 702	$ 5,425	$ 6,127
Safety	$ 81	-	$ 81
Net In-Service Additions	**$ 9,779**	**$ 5,425**	**$ 15,204**

c) Hydro Ottawa has seen a major impact due to the number of leaking transformers discovered every year. However these transformer leak issues are localized and confined to a certain manufacturer type and region. The leaks are due to the quality of a specific type of transformer from a single manufacturer.

i) Hydro Ottawa has adopted remedial measures to phase out the problematic units of the identified manufacturer and replace them with a type, observed to be more robust based on operational performance in Hydro Ottawa's service territory. Otherwise, Hydro Ottawa creates Corrective Action Reports (CARs) to identify and monitor corrective actions for repairs and remediation of a systemic problem (with the manufacturer). CARs are utilized to pinpoint the root cause of failures, particularly within the warranty period. They also help in defining corrective actions and resolutions to manage the performance of in-service assets or prevent failures in new assets of a similar type. Hydro Ottawa's observed oil leak issues, however, had fallen outside the warranty period.

d) The gatekeepers failed to meet the expected functional requirements during the trial testing phase and did not proceed to installation. During functional testing, the first-generation meters were deemed to be incompatible with the new generation of Gatekeepers. Hydro Ottawa's meter population is composed mainly of first-generation meters installed over 15 years ago (refer to Figure 74 of Schedule 2-5-7 - System Renewal). The vendor was unable to correct the failures and deficiencies, as the first generation of meters are legacy meters.

e) As presented in Table B, the Gatekeeper project incurred $76,000 in capitalized expenditures and additions between 2022 and 2024. Given that the Gatekeeper solution was subsequently deemed unsuccessful and therefore never brought into service, these costs were expensed to OM&A in 2025.

Table B - Total Capital Expenditure and Capital Additions ($000) 2022-2024[1]

	Historical Years			Total
	2022	2023	2024	2022-2024
Capital Expense	$ 29	$ 36	$ 12	$ 76
Capital Additions	$ 29	$ 35	$ 12	$ 76

[1] Totals may not sum due to rounding

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-33

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 1 / Schedule 1 / p. 15 (pdf Exhibit 2 part 1, p. 15)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 5 / p. 87 (pdf Exhibit 2 part 4, p. 87)

Preamble:
Hydro Ottawa states that for the:

- Capital Upgrades: “The Riverdale Switchgear Upgrade was delayed due to necessary scope adjustments required to adhere to capacity planning requirements identified through area planning.”
- Grid Technologies: “Once the [Advanced Distribution Management System] ADMS initiative commenced, detailed planning revealed significant gaps in the original requirements.”… “Hydro Ottawa notes that the ADMS program is currently undergoing a comprehensive review, and therefore specific details of the Grid Technology budget program, including the capital budget and timing of in-service additions, are subject to significant change.”

Hydro Ottawa also notes “that the ADMS program is currently undergoing a comprehensive review, and therefore, specific details of the Grid Technology budget program, including the capital budget, are subject to significant change.”

QUESTION(S):

a) Should the significant gaps in the original Advanced Distribution Management System (ADMS) requirements have been identified and addressed during the project planning phase? Please discuss.

b) What portion of the 135% overspend was attributable to these gaps, and what portions were attributable to other factors? Please list all key factors and quantify the amount of overspend attributable to each factor.

c) By what date does Hydro Ottawa anticipate the scope and budget of the ADMS program will be finalized?

d) Given the ADMS program scope uncertainty, what is the expected range of capital expenditures on this program over the upcoming test period?

e) What is the expected range of spending beyond the test period?

f) Please provide the net present value over the expected service lives of the ADMS assets of:

   i) The expected operational savings that will be delivered.

   ii) The customer interruptions that will be avoided.

   iii) Any other quantifiable value produced by these investments.

g) Please provide the supporting business case or benefit/cost analysis that supported the original ADMS investment decision, and a revised business case or benefit/cost analysis using the best currently available information.

h) Is the 135% ADMS overspend a gross value, or net of this $4M redistribution? Please discuss.

i) Will any of the investments made to date in this program be stranded following the comprehensive review? Please explain.

RESPONSE(S):

a) The budget amounts presented in the 2021-2025 Rate Application were derived from a preliminary planning exercise and did not account for detailed project scopes. A more comprehensive planning phase was intended, and took place in 2021/2022. During this subsequent detailed planning, Hydro Ottawa identified significant gaps in the original scope and resource requirements. As further detailed in Section 5.3.2 of Schedule 2-5-5 - Capital Expenditure Plan, these factors were not known at the time of the preliminary planning exercise for the 2021-2025 rate application.

b) The gross capex overspend of $12M (135%) is almost entirely attributable to the gaps identified during detailed project planning, as noted in part (a) above. As discussed in Schedule 2-5-5 - Capital Expenditure Plan on page 86 and in part (h) below, this $12M overspend was mitigated by a reallocation of funds from the Field Area Network, resulting in a net variance of $7.8M.

The key components of the identified gaps were adding dedicated internal resources, a larger external consulting team, and including schematics in the project scope.

Approximately $4.4M (41%) resulted from adopting a dedicated internal project resource model and $5.0M (37%) from expanded professional services, which includes pricing increases in the rates of the vendors due to delays in project implementation (further discussed in Schedule 2-5-5 - Capital Expenditure Plan, pages 86-87). The remaining $2.6M (22%) was due to the inclusion of schematics in the project scope.

c) As noted in the response to interrogatory 1-Staff-1, Hydro Ottawa paused its ADMS program in early 2025 to complete a comprehensive review. This review was vital for navigating the ongoing energy transition, addressing dynamic changes within the energy sector, and optimizing operational capabilities. The review prompted modifications in the sequencing of functionality to reflect current priorities and technological advancements, focusing on essential capabilities for the 2026 to 2030 period.

A formal ADMS Program Charter was prepared (please refer to Attachment 2-CCC-15(D) - ADMS Program Charter). The scope of the ADMS program is laid out in three releases as detailed on page 7 of the charter.

- Release 1: The detailed scope has been defined, and the detailed budget is expected in Q3 2025. While the Program Charter indicates that the timeline for delivery of Release 1 is July 2025 to December 2025, the in-service capital additions for this Release have been moved to February 2026.

- Release 2: The detailed scope and budget is expected to be available in Q4 2025 and the in-service date for these additions were moved to December 2027.
- Release 3: The detailed scope and budget for Release 3 is anticipated to be available by Q4 2027.

The ADMS Program charter does not cover beyond 2030.

d) As noted in part (c) above, Hydro Ottawa is awaiting the detailed budgets by Release, however Section 3 of the ADMS Program Charter (Attachment 2-CCC-15(D) - ADMS Program Charter) provides an analogous estimate. The expected capital expenditure over the test period if all 3 Releases are completed would range between -/+ 10% of the $25.8M estimate, that is between $23.2M and $28.4M. However, as noted in Table A below (updated via the response to interrogatory 1-Staff-1), the capital expenditures for the 2025 to 2030 period total $13.7M. Factoring in the spend up to June 2025, this would indicate a potential shortfall using the higher end of the estimate range of approximately $15.3M in the test period. This shortfall is planned to be addressed using the proposed budget of the overall Grid Modernization program. This will be achieved through a structured review and reprioritization of initiatives within the Grid Modernization program. This reprioritization has not yet occurred; however, Hydro Ottawa does not plan to request additional funding as part of this rate application. Table B below provides the overall Grid Modernization program, including Grid Technology, and has been updated for the shift in capital expenditures as outlined in the response to interrogatory 1-Staff-1 and Table A. For more details on the other budget programs in Table B, refer to the response to interrogatory 2-Staff-119 part (a).

Table A - Grid Technology Historical, Bridge and Test Year Expenditures ($'000 000s)

Budget Program	Historical Years				Bridge Year	Test Years				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SCADA Upgrades	$ 0.2	$ 2.6	$ 5.6	$ 5.1	$ 3.3	$ 3.4	$ 0.6	-	-	-
ADMS Upgrades & Enhancements	-	-	-	-	-	-	$ 1.0	$ 0.1	$ 5.0	$ 0.3
TOTAL	**$ 0.2**	**$ 2.6**	**$ 5.6**	**$ 5.1**	**$ 3.3**	**$3.4**	**$ 1.6**	**$ 0.1**	**$ 5.0**	**$ 0.3**
5-YEAR TOTAL					**$ 16.8**					**$ 10.4**

Table B - Grid Modernization Program Expenditures, 2026-2030 ($'000 000s)

Budget Program	Forecast Years				
	2026	2027	2028	2029	2030
Data and System Integrations	$ 0.8	$ 0.6	$ 0.5	$ 0.5	$ 1.1
Metering Renewal	$ 13.0	$ 13.4	$ 14.2	$ 17.8	$ 19.8
Capacity Upgrades	$ 4.1	$ 13.9	$ 20.2	$ 14.3	$ 8.7
Distribution Enhancements	$ 9.4	$ 9.7	$ 10.2	$ 10.6	$ 11.0
Grid Technologies	$ 3.4	$ 1.6	$ 0.1	$ 5.0	$ 0.3
Control and Optimization	$ 0.7	$ 1.8	$ 0.4	$ 0.4	$ 0.4
Field Area Network	$ 3.0	$ 4.8	$ 6.9	$ 4.0	$ 2.1
TOTAL	**$ 34.3**	**$ 45.9**	**$ 52.4**	**$ 52.5**	**$ 43.3**

e) The budget requirements beyond 2030 have not been determined for this program. Please note that grid modernization will evolve as the energy transition evolves, and it is expected that new functions and requirements will be introduced by Hydro Ottawa's next rate application.

f) An ADMS is a foundational operational imperative for Hydro Ottawa. Its purpose is not to generate a direct return on investment that could be measured with a traditional NPV analysis, but rather to ensure the fundamental safety, reliability, and security of the electric grid. The system is an essential investment that allows Hydro Ottawa to manage the evolving energy landscape, from integrating distributed energy resources to preparing for future smart grid

technologies. Without it, the grid's operational integrity would be compromised, exposing the utility and the public to unacceptable levels of risk. Therefore, the business case is not one of financial gains, but of maintaining operational viability and meeting Hydro Ottawa's core mandate to deliver safe, reliable power to our customers.

i) Although operational savings were not quantified, Hydro Ottawa does anticipate some efficiency gains, as outlined in the 2021-2025 Rate Application and in part (c) of the response to interrogatory 2-Staff-75.

Implementation of ADMS will consolidate multiple tools used by system operators, thereby reducing the need to manage data and decisions across systems. Currently, each tool represents a certain function to the operator, the disparate nature of the separate tools significantly adds to the workload of the operator and detracts from the clear decision making process. This is particularly challenging in responding to major outage events. This fragmented workflow and the diverse skills needed for multiple systems also directly increases the training investment and extends the time required for a new operator to achieve full proficiency.

ii) An Advanced Distribution Management System (ADMS) cannot prevent the vast majority of interruptions from happening. The centralization of information provided by the system can support the reduction of outage impacts through increased situational awareness, outage prioritization and process automation.

iii) As discussed above, ADMS is a foundational technology; therefore, no quantifiable values were developed. However, examples of additional value inherent to this solution include:

- Enhanced outage communication, including restoration times are key drivers of increased customer satisfaction.
- Enhanced grid visibility, combined with improved field communication and coordination, directly leads to better safety outcomes.
- Provides the foundation for grid flexibility, enabling the integration and management of Distributed Energy Resources (DERs) and supporting DER Management Systems (DERMS) to unlock flexible hosting capacity.

g) The initial investment decision for Hydro Ottawa's Advanced Distribution Management System (ADMS) program, formerly known as the 'Self-Healing Grid Program', which focused on improving the electricity grid's reliability, was based on a business value assessment performed in 2018. The program's approval was granted by the Smart Grid Steering Committee,[1] acting under the executive co-chairmanship of Hydro Ottawa's Chief Information Officer and Chief Electricity Distribution Officer.[2] The latest ADMS Program revised costs benefits are addressed in part f) and described in Attachment 2-CCC-15(D) - ADMS Program Charter.

h) The 135% ADMS overspend is a gross value. Please refer to Schedule 2-5-5 - Capital Expenditure Plan, Table 27 for additional details. The net overspend is 90% after factoring in the $4M redistribution.

i) No investments made to date in this program will be stranded. The comprehensive review, conducted in 2025, prompted modifications in the sequencing of functionality, not altering or discontinuing systems or functionality. Details regarding the sequence of functionality can be found in Attachment 2-CCC-15(D) - ADMS Program Charter.

[1] Now referred to as the Grid Modernization Steering Committee
[2] Now Chief Operating Officer

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-34

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 1 / Schedule 1 / pp. 17-18 (pdf Exhibit 2 part 1, pp. 17-18)

Preamble:
Hydro Ottawa states, regarding fleet replacement, that "Capital additions are expected to exceed approved amounts by $1.2M, due largely to unforeseen increases in vehicle costs well beyond historical annual inflationary increases as a result of COVID-19 supply chain disruptions. Nine vehicles were also deferred to offset the inflationary pressures."

Hydro Ottawa states the main driver of the Buildings – Facilities increased expenditures was construction of a shared access roadway at the East entrance to the Hunt Club Road facility, which was driven by a 3rd party.

For the General Plant category, capital additions are projected to be $13.0 million below approved amounts. Further details regarding these variances by capital program are presented in Table 10.

QUESTION(S):

a) What is Hydro Ottawa's estimation of the annual percentage inflationary increase in vehicle costs in each year of the historical/bridge period on a unit basis?
b) What part of the overrun was driven by this requirement?
c) Why was this requirement not identified in the initial estimate?
d) Was the third party required to make any CIAC payment in support of this scope addition? Please discuss.

RESPONSE(S):

Hydro Ottawa notes that the page reference in this interrogatory question should be pp. 14-16.

a) Please refer to Table 30 in Section 4.2 of Schedule 1-2-5 - Impacts of Inflationary Pressure for vehicle unit price increases in 2021 compared to 2024. Over the 2021-2024 period, the price of the most commonly purchased vehicles increased at a rate of 7.3% to 12.7% per year. The 2024 price of vehicles was 23.5% to 43.1% higher than in 2021.

b) Hydro Ottawa assumes that questions b), c) and d) refer to the Buildings - Facilities increased expenditure. Hydro Ottawa noted four main drivers causing capital additions to exceed budgeted amounts - of which the shared access roadway was one. The shared access roadway and accompanying driveway modifications at the East entrance to the Hunt Club Road facility cost $0.8M, representing approximately 16% of the overrun.

c) Although Hydro Ottawa was aware of the future construction of a shared roadway by a third party, Hydro Ottawa's share of the costs was not included in the 2021–2025 application because work was not expected to start until after 2025. In addition, Hydro Ottawa lacked details on the roadway design or any requirement to modify the existing driveway. However, modifying the driveway created a safer entrance and exit onto Hunt Club Road.

d) The third party managed the construction and paid for the shared roadway, and Hydro Ottawa agreed to contribute $0.5M toward the cost as part of the initial purchase of the land.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-35

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 1 / Schedule 1 / pp. 23-24 (pdf Exhibit 2 part 1, pp. 23-24)

Preamble:
Hydro Ottawa states the following regarding variance analysis: “approximately $8M is attributable to unforeseen cost overruns for the LRT Phase II System Expansion works, due to changes in the project’s timeline and scope”. Additionally, regarding variance analysis, “System Access capital additions are expected to be $10.5M (68%) higher than OEB-Approved amounts, the main drivers continue to be persistent higher than budgeted volumes and unit costs in Customer Connections, and overages in System Expansion resulting from the Department of National Defence Dwyer Hill Training Center Upgrade and the OC Transpo’s Zero Emission Buses.”

QUESTION(S):

a) Were the changes in the LRT Phase II System Expansion project's timeline and scope driven primarily by Hydro Ottawa or by OC Transpo?
    i) If primarily by OC Transpo, was the CIAC amount increased to cover part of the increased scope?
    ii) If primarily by Hydro Ottawa, please explain why the scope and timeline had to be changed.
b) What system expansion changes were driven by the OC Transpo ZEBs?
    i) Did OC Transpo make a CIAC payment to offset the associated expansion costs? Please discuss.
c) Was DND required to make a CIAC payment for the Dwyer Hill Training Center Upgrade upgrade? Please discuss.

RESPONSE(S):

a) All changes in timeline and scope for LRT Phase II System Expansion project were driven by the customers. System expansions were executed based on projected station energization milestones provided by the customer(s). Along with post-COVID inflation pressures, these factors contributed to cost increases.

i) Any subsequent scope of cost increases required re-running the Economic Evaluation. Consequently, any resulting increases to the CIAC/contribution would be required from the customer.

ii) As established above, changes were primarily customer-driven.

b) The system expansion required for the ZEB project primarily involves extending a feeder from Hawthorne station to the newly constructed customer-owned substation located on the OC Transpo property as an interim solution and the establishment of a permanent connection via two 44 kV feeders between OC Transpo and the new Hydro Road Municipal Transformer Station (Hydro Road MTS is being constructed primarily to serve OC Transpo's ZEBs). More details are available in Section 4.3.2 of Schedule 2-5-6 - System Access Investments.

i) Yes, OC Transpo has consistently been making CIAC payments to offset the associated costs as determined through the economic evaluation calculations guided by Appendix B of the Distribution System Code, adhering strictly to the agreed-upon payment schedule.

c) Yes, DND was required to make CIAC payment for the Dwyer Hill Training Centre Upgrade for a portion of the station upgrade and distribution system expansion required. Capital contributions required from DND were determined through economic evaluation calculations guided by Appendix B of the Distribution System Code.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-36

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / p. 37 (pdf Exhibit 2 part 2, p. 37)

Preamble:
Hydro Ottawa defines its investment priority Enhancing Grid Resilience as “Focusing on enhancing grid resilience by proactively upgrading infrastructure and implementing measures to protect against increasingly frequent and intense severe weather events and cyber threats.”

QUESTION(S):

a) Is Hydro Ottawa increasing, or has Hydro Ottawa recently increased, its design standards to withstand stronger winds, and greater ice or snow buildup? If yes:
   i) Please provide the old standards, the new standards and the analysis used to determine the revised structure strength parameters that will be used in line design going forward.
   ii) Will existing line assets that do not satisfy the new design standards be proactively upgraded to achieve those standards prior to reaching their expected service lives?
   iii) Provide any analysis showing the correlation between pole failures and pole condition for the poles that failed during the extreme weather events noted over the historical period.

RESPONSE(S):

a) Yes, Hydro Ottawa has enhanced its design standards to withstand stronger winds and increased accumulated ice thickness.

i) Please refer to Attachment 2-Staff-36(A) - GDS0003 R5 Overhead Design Guidelines, section 5.12 Guying and Anchoring, for the old standard and Attachment 2-Staff-36(B) - GDS0003 R9 Overhead Design Guidelines, section 5.13 Guying and Anchoring, for the new standard. The analysis used is available as Attachment 2-Staff-36(C) - Storm Hardening Study - Feb 2023.

ii) Hydro Ottawa does not currently have a plan in place to upgrade existing infrastructure to the new design standards before reaching its expected service life. However, a review of all North-South pole lines that were impacted by the 2023 Derecho was conducted and led to upgrades to guying and anchoring, ties to neighbouring circuits, and redistribution of customers to different circuits.

iii) Hydro Ottawa has analyzed the condition profile of the poles that failed prior to the onset of the Derecho event and the summary is presented in part (a) of the response to interrogatory 2-Staff-29. Based on the analysis, only 52% of the poles impacted by the Derecho event were in a Very Poor/Poor condition. While the pre-existing condition of a pole is a contributing element, it is not a sole determinant of failure during severe weather.

HydroOttawa		TITLE: Engineering Specification	
RECOMMENDED:	**M. Wyndham, P.Eng**	NO: **GDS0003**	REV: **5**
APPROVED:	**B. Hazlett, P. Eng**		
REV. DATE:	**2019-02-15**		

Overhead Design Guideline

REVISION SHEET

Revision	Description of Change	Date	Initial
0	Original Document	2003-05-12	ml/bb
1	General revision	2005-04-12	rm/csm
2	General revision & Pole materials	2006-03-08	rm/csm
3	Section 5.6, Grounding of Steel Arms	2009-01-10	cm/csm
4	Section 5.3, Pole Framing and Circuit Position	2009-05-12	cm/csm
5	Section 5.9, Local Control Devices, Added, General revision	2019-mm-dd	rw/mw

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1.0 Introduction

This document outlines the general overhead distribution design philosophy to be used by Hydro Ottawa staff or contractors when designing and constructing Hydro Ottawa's overhead distribution system. These standards and practices will meet regulatory requirements and produce a cost effective, reliable, and maintainable overhead distribution system.

Prior to amalgamation, many predecessor utilities adopted the 1992 Ontario Hydro overhead standards manual as a general design guideline for constructing its overhead distribution system. Deviations from this manual were allowed to meet special or local circumstances. The 1992 Ontario Hydro standards manual was produced to primarily support a rural distribution system and not a combination rural/urban system similar to Hydro Ottawa.

This document will assist to develop, maintain, and update new overhead distribution construction. Where Hydro Ottawa standards do not exist, the Ontario Hydro Manual (1992) or specific pre-amalgamation utility standards shall be used until an in house standard is developed.

2.0 Reference

- CSA - C22.3 No. 1 - Overhead Systems.
- CSA - C22.3 No. 5.1 - Recommended Practices for Electrical Protection – Electric Contact Between Overhead Supply and Communication Lines.
- Hydro Ottawa - ECS0012 - Conditions of Service.
- Hydro Ottawa – GAS0001 - Overhead Standards Guying and Anchoring – Engineering Specification
- Hydro Ottawa - GDS0014 - Negotiated Joint-Use Design and Installation Guideline Between Hydro Ottawa Limited and Hydro One Networks Inc.
- Hydro Ottawa – DFS0012 Signing Authority for Technical Based Documents
- Hydro Ottawa – OPT0001 - Pole Selection Table for Wood Poles
- Hydro Ottawa - Various Overhead Distribution Standards.
- Municipal Electric Association - Guide to Municipal Standard Construction, Part 2 – Overhead, 1996.
- Ontario Electrical Safety Code.
- Ontario Hydro - Overhead Distribution Standards, 1992 Ed.
- Ontario Regulation 22/04 - Ontario Electrical Distribution Safety Code.
- Ottawa Hydro - Specifications for Overhead Line Construction 4kV & 12kV.
- Utilities Standards Forum - USF Standards

3.0 Scope

This design guideline is intended to be used for the design of new overhead distribution plant, both greenfield and established urban and rural service areas while meeting Regulation 22/04 requirements.

4.0 Pre-amalgamation Utility Construction Standards (Legacy) and other Utility Standards

Hydro Ottawa has internal pre-amalgamation line construction standards from the predecessor utilities and have purchased the rights to use some external construction standards from the following groups:

1. Ontario Hydro, line construction standards prior to 2004 (now Hydro One Networks Inc. – referred to as HONI hereafter);
2. Mississauga Hydro, line construction standards posted on the intranet prior to 2002 (now Enersource – referred to as ENER hereafter);
3. USF Standards

These standards as well as the predecessor utilities standards can be used for like-for-like replacement of existing installations.

Any other use will require Project Plan approval from the appropriate signing authority as per DFS00012.

The use of old construction standards will also depend upon availability of the older stocked items that may be depleted or no longer available.

5.0 Design Approach

There are often many possible solutions to any design problem. The purpose of this section is to provide an overall design philosophy to aid in the decision making process, and to encourage industry standard, “best practices”.

5.1 Hydro Ottawa Primary Voltages Boundaries by Area

Voltages boundaries may change due to loading, reliability, economics, accessibility, and/or specific problems. Where feasible, extensions and interconnections will be promoted to provide capacity sharing and improved contingency planning.

Area	Voltages (kV)
Ottawa	4.16, 13.2
Nepean	8.32, 13.8, 27.6, 44
Gloucester	8.32, 27.6, 44
Kanata	8.32, 12.47, 27.6, 44

Goulbourn	8.32, 27.6, 44
Casselman	8.32

Table 5.1: Area Primary Voltages

5.2 Equipment Insulation Levels

All equipment connected to the distribution system must meet or exceed the Basic Insulation Level (BIL) requirements shown in Table 5.2.

Voltage Level (kV)	BIL (kV)
4.16	60
8.32	95
12.47	95
13.2	95
27.6	125
44	250

Table 5.2: BIL Requirements

All new distribution line rebuilds are to be to accommodate 28 kV primary circuits as shown in Table 5.3, with the exception of spot replacement within the 4.16 kV system.

In order that we may improve system reliability, and minimize the number of stock items, the following guidelines will apply when selecting insulators:

Insulation Level	Insulation Levels
15 kV	4.16 kV Spot Replacement
28 kV	All Voltages 13.8 kV and below
46 kV	27.6 kV and 44 kV primary circuits
69 kV	44 kV dead ends and
69 kV	44kV system in a contaminated environments
69 kV	44kV primary on conductive poles

Table 5.3: Insulation Levels

5.3 Circuit Position

Pole framing for multiple circuits of unlike distribution voltages or a combination of sub-transmission and distribution voltages shall consider the separation criteria outlined in this section.

5.3.1 Vertical Separation of Different Voltages

Vertical separation of unlike distribution voltages or a combination of sub-transmission and distribution voltages shall be framed having the highest voltage at the highest level on the pole.

44 kV sub-transmission circuits shall not be installed at the same level on a pole as any 13.2 kV sub-transmission circuit.

44 kVand 13.2 kV sub-transmission circuits shall not be installed at the same level on a pole as any other distribution circuit.

Local distribution circuits (typically lower voltage) which remain in place following a voltage conversion will be framed having the highest voltages at the highest level on pole.

5.3.2 Horizontal Separation of Different Primary Voltages

Horizontal separation of unlike distribution voltages may be established provided the following criteria have been considered in whole or in part.

The conductor height and clearance above grade has been restricted (e.g. transmission line crossing the pole line). Side by side framing by either post pin or cross arm type construction may apply.

New load being supplied to a growth area at a higher voltage that has been approved by the Asset Manager where the lower voltage is being expressed through the growth area.

Old voltage is expressed through the growth area and does not supply any new load.

Plans have been approved by the Asset Manager for the conversion/removal of old circuits within a five-year planning window or for the installation of step transformers to supply remaining load at the old voltage level.

Cross arm construction or alternate technology was considered and ruled out.
Pole height is limited by engineering design parameters.

Pole height is limited by capability of truck reach.

Different sized insulators will be used to assist in the identification of side by side voltages.

Preliminary design drawings indicate in bold lettering “BACK TO BACK DIFFERENT VOLTAGES”.

Circuit voltage must be identified via GIS as shown in Figure 1 below.

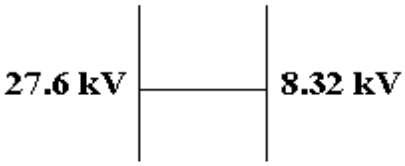


Figure 1

Field tags as shown in Figure 2 are placed on each new pole installation just below the lowest phase of each back to back different voltage. Existing installations shall be field tagged when crews are competing significant re-work on the pole or as authorized by the Asset Manager.



Figure 2

5.4 Pole Height, Strength, and Spacing

The pole height, strength, and spacing shall be determined using the following.

CSA overhead standard C22.3 No.1 will be used to determine vertical clearances over roads, highways, railways, navigable waterways, etc.

System neutral is to be normally installed at 7.6 m [25’] minimum (parallel & perpendicular) above all roadways. This clearly sets the reference height for telecommunication companies.

Improved appearance (armless) construction shall be used with new construction projects. Exceptions to this include; height restrictions, 4.16 kV spot replacement, potheads, or temporary services (see Section 2.0 for use of old construction standards).

Vertical construction is encouraged to facilitate the future installation of an additional circuit(s).

The maximum number of three phase circuits per pole for new builds shall be 4.

Secondary buses, services, and neutrals shall be attached below transformers.

Pole heights and class shall be based on Hydro Ottawa standard OPT0001. Choice of pole depends on number of circuits and span lengths.

For rural, non-street light inter-pole spacing, 50 m spacing shall be used for standard construction. The maximum inter-pole spacing shall be 65 m unless specific crossings are custom engineered.

Generally, the maximum pole height that can be reached using the existing Hydro Ottawa fleet is 75’.

Pole spacing should vary to dampen conductor gallop.

A vertical maximum of 5’ fibreglass pole extension shall only be used on an existing pole where strength or aesthetics are not a requirement.

Along major arterials and other aesthetic sensitive areas, alley arms should be avoided.

Adequate vertical space between circuits must be available for access by aerial devices. A minimum 1.5 m [5’] vertical space must also be available between circuit phases on pole lines well off the travelled portion of the road or where access by aerial devices to the field side of the pole is restricted.

Within the old urban core, 4 kV circuit rebuilds and extensions can have a minimum of 900 mm [3’] vertical spacing.

1.8m [6’] vertical space shall be left between 44kV sub-transmission and lower primary distribution voltages.

Adequate vertical space must be left between the lowest distribution phase conductor and the system neutral for installation of transformers and overhead to underground cable transitions (risers).

All primary voltage in-line poles shall be the same height. These in-line poles shall not be cut down to the telecommunications height and left indefinitely.

Along major arterials and other aesthetic sensitive areas, poles should not be stepped in line with the existing pole line if 20-metre separation between poles cannot be achieved. Re-arrange the overhead equipment to obtain the required aerial real estate for a new/upgraded customer connection.

5.5 Third Party Plant on Poles

Third party’s or its contractors shall not carry out work on/in Hydro Ottawa support structures (ex. poles, manholes, handholes) without approval from Hydro Ottawa.

In no case shall third party's or its contractor's work on Hydro Ottawa poles above any live conductor, install an underground service on a pole or in a manhole/handhole where Hydro Ottawa cable is present. Moreover, Safe Limits of Approach as specified in the EUSA Rulebook shall apply.

5.5.1 Telecommunications

A pole attachment agreement will be required for all telecommunication equipment, third party boxes, street lighting, and occasional decorative banners & lights. Exceptions shall be granted for small secondary electrical disconnects (≤ 100 A), non-electric traffic signage, non-electric bus stop signs, poster collars, and mail boxes.

A 600mm telecommunication corridor is outlined in Hydro Ottawa Standard OLS0001. This telecommunication space allows a maximum of 3 parallel, vertically mounted (no offset brackets) telecommunications support strands 300 mm apart on the same side of the pole. Some locations may be restricted to fewer or no communication strands due to height restrictions, pole strength, or aesthetics.

Telecommunication support strands on poles with primary circuits shall be bond to a grounding system at a maximum of every 300 m as per CSA standard C22.3 NO. 5.1.

Third party boxes e.g. power supplies, amplifiers antennas etc. shall be mounted below the telecommunication space (see OLS0001). Antennas and third party non-electrical supply boxes shall not be installed within one pole span of critical crossings (such as railways, waterways, highways, transit ways, cliffs). The 15 metre sight line triangle at all public road intersections, turning islands, and road way mediums shall be kept clear of any antennas. Antennas shall not be within 100 meters of other pole mounted antennas and non-electrical supply boxes. Antennas and non-electrical supply boxes shall not be installed within ±60 degrees from perpendicular to commercial building signs.

Parallel telecommunication support strands shall not cross over one another between poles.

Telecommunication companies shall not install riser cables on poles that have more than 33% of the circumference [120 degrees] taken up with existing riser cables and cable protection (guards, duct laterals and concrete curbs). Re-use of existing cable guards is mandatory.

5.5.2 Street Lighting

In urban areas and along major arterial roads, sufficient height and inter-pole spacing shall be available for future roadway street lighting. Where possible, re-alignment of anchoring stub poles to accommodate street lighting luminaries shall also be considered to reduce pole congestion and aesthetics concerns.

Streetlight continuous pole lines shall not be installed within 5.0 m parallel to primary conductors to reduce pole congestion and aesthetics concerns.

For third party worker safety, streetlight, telecommunication, and traffic poles shall not be installed within 3.5 m of primary conductor and 1.5m of secondary or neutral conductor without written permit approval.

Overhead electrical service wire can be temporarily (up to one year) installed to service a street light pole and luminaire from a Hydro pole until the normal underground street light service wire is repaired.

5.6 Riser Poles

5.6.1 General

For reliability, install only one primary trunk or station feeder egress riser per pole. In dense urban areas, two primary service risers may be allowed on a single pole if there is no practical alternative.

The pole shall not have more than 1/3 the circumference of the pole with riser(s) to allow for pole maintenance and space to climb if required.

All primary risers shall be guarded from the base of the pole to 150 mm above the system neutral. The guards shall be no less than 200 mm below the neutral.

Guards shall make direct contact to the pole (no offset). All primary underground service risers on poles shall have a reinforced, poured concrete curb for protection where required.

Electrical risers shall be installed on the side of the pole opposite (downstream) to traffic flow where possible for system protection.

A pole ground shall be installed at all primary riser locations.

No permanent secondary metering shall be installed on utility owned poles.

Only contractors qualified by Hydro Ottawa or utilities with a Municipal Access Agreement shall connect to Hydro Ottawa owned support structures.

Electrical connections onto Hydro Ottawa owned support structures shall meet Hydro Ottawa cable standards e.g. no metal sheath cables such as teck, pyro, or coreflex.

5.6.2 Primary Riser Poles

The primary cables shall rise up the pole and be terminated immediately below the associated primary circuit.

All connections onto the primary conductor greater than 200 Amp shall be power installed wedge type connectors.

Connections to the primary conductor less than or equal to 200 Amp shall made via stirrup and hot line clamp. Connections made to copper primary conductor can be made with the hot line clamp directly

Connections less than 200A shall be fused with the exception of the Ottawa 13.2 kV Sub-Transmission and 44kV sub-transmission.

Connections greater than 200A will be made with solid blade switches or line tap switches.

Lightning arrestors shall be installed at all riser locations and shall be connected to the multi-ground system neutral. See GDS0011. A pole ground shall be installed at all riser locations. The impedance shall be measured and verified less than 25 ohms.

5.6.3 Pothead Primary Riser Poles (Legacy)

For any lead cable applications utilizing pothead construction, the former Ottawa Hydro framing standards are to be used.

5.6.4 Secondary Riser

All secondary risers shall be in conduit complete with a weather head up to the secondary power space on the pole. The drip loops of the secondary conductors shall be at least 200mm above the telecommunications space.

For an underground service on a utility owned pole, the service head shall not be less than 1020 mm [40”] above the telecommunication equipment. The service head shall be installed so that the bottom of the conductor drip loops will be a minimum of 200mm above the communications space.. In every case the contractor shall obtain instructions from Hydro Ottawa before installing the cable on the pole.

All services greater than 200 A (including a temporary service) shall leave the pole by an underground riser.

5.7 Overhead Equipment Location Considerations

For safety and reliability, the following location and distance offsets should be taken into to consideration.

For new construction, no primary or secondary conductors over swimming pools (see Conditions of Service, Section 3.0).

New permanent structures (that are ‘normally’ occupied such as houses, garages, buildings, buildings with balconies, mobile trailer homes) shall not be located within

the safe limits of approach (for <46kV, it is 3 metres from the maximum outward conductor swing) plus an additional 2 metres for building maintenance (such as painting, roofing, window washing, brick pointing); this would mean a minimum of 5 metre radial separation from the closest primary phase conductor. In addition, every attempt shall be made to keep existing buildings at least 2 metres horizontally outside of the closest primary phase conductor with respect to the vertical plane (from the ground to the primary phase conductor). On an individual (case-by-case) basis, portable and temporary (less than 1 year) structures such as garden sheds < 100 ft-sq and construction trailers may be installed directly under primary conductors where there is sufficient height (3 m vertically plus 2m for a person standing on top of the temporary structure) and the structure is grounded (minimum of <25 ohms with a #4 AWG Copper conductor to a 3 meter ground rod) although a reasonable attempt should be made to avoid such arrangements.

Primary risers and distribution transformers are to be kept away from intersections. If equipment is forced towards an intersection, priority shall be given to keep primary risers away from intersections versus distribution transformers.

Fuses and switches should be positioned on the pole for ease of operation and maintenance. The choice of location/position must consider safety (aerial device set-up, possible equipment failure during operation, etc.).

To reduce the possibility of pole fires, steel cross arms shall be bonded to ground when conductors are connected via porcelain or glass insulators. Where conductors are connected to a steel arm via silicone or polyethylene insulators, it is not necessary to bond the arm to ground.

In-line switches, fuses, or mid-span openers shall not be located over railways, transit ways, roadways, or navigable waterways.

With overhead secondary services, flying (mid-span) taps shall have adequate back-support for conductor larger than #2 AWG triplex.

In urban areas having no ditches, all primary service road crossings will be underground.

In urban areas having no ditches, all secondary services greater than 200A will be underground.

Overhead secondary services can be unsupported in length up to 38 meters from the supply pole to the standpipe. Any overhead spans greater than the 38 meters will require a service pole to be stepped-in or a reinforced standpipe installed.

Electrical switch operating handles shall be installed on the side of the pole opposite (downstream) to traffic flow where possible for system protection.

In addition to Section 5.5 (Third Party Plant on Poles), utility devices that locally control the aerial primary equipment can be mounted as low as 1500 mm above grade in non-sensitive commercial / heritage / residential areas. Such devices shall be

protected from harm (eg. snow ploughs, vehicles, …), not interfere with pedestrian or traffic flow, and have adequate safe guards to ensure public safety. All switch motor operators shall be installed near grade to allow for manual operation. All other utility devices (eg. secondary disconnect switches, RTU's, …) shall be mounted above 3500 mm from grade.

5.8 Environmental Considerations for Chemically Treated and Oil Filled Equipment

Every attempt shall be made to keep wooden poles treated with CCA preservative way from schoolyards, playgrounds, and open waterways. Other approved pole materials should be considered in these circumstances.

Oil filled equipment shall not be installed within 15m of open waterways unless there is a dedicated oil containment facility.

Oil filled distribution transformers are to be kept away from intersections unless there is no other option. Primary risers take precedence over transformers (see section 5.6).

5.9 Pole Location Considerations

The total number of poles (Hydro, Bell, street lighting) should be minimized. This requires joint planning and construction along the road allowance. Parallel pole lines on opposite sides of the street should be avoided unless the roadway is at least 6 lanes wide.

It should be assumed that all intersections will at some time be modified by the road authority so all attempts should be made to install poles 3 metres from the intersection curbs and use 'flying taps' to make electrical connections at the corner. This will also reduce the exposure to vehicle accidents.

A pole shall not be installed in small medians (< 6 m wide) or turning islands in the roadway where possible.

In urban areas, no overhead transformers, primary risers, or secondary service risers >200A @ 240V shall be located within the 15 meter sight line triangle of intersections or major commercial entrances with curbs due to the greater chance of vehicle accidents and the difficulty of blocking both streets to do any maintenance work.

In urban areas, poles should be located so as not to obstruct doorways, fire hydrants, or driveway entrances.

In existing urban areas, poles located along curb lines shall be set so that there is a minimum of 500 mm, where possible, between the nearest surface of the pole and the roadside curb / sidewalk. This will reduce damage during snow removal operations and allow city bus operations. In tight offset locations (<500 mm), [¼"] steel plate

shall be used to protect the pole from snowplough damage, and protective bollards maybe required to protect low mounted switching handles.

Protective bollards will guard Hydro Ottawa primary circuit carrying poles that are exposed (ex. no curbs) and located in the middle of major parking lots where vehicle speeds of > 20 km/h can be easily achieved.

In urban areas without a curb on an existing roadway, a pole shall be installed at least 4.0 metres as a minimum back (dependent on traffic speed and slope of shoulder) of the existing hard surface if possible.

Typically in rural areas, the poles are to be installed one metre off property line. An offset from the property line greater than 1m may be required to prevent wires overhanging private property due to the use of larger pole hardware such as brackets and insulators. Installing poles at the bottom of the roadway ditch should be avoided. If a pole is installed on the roadside of the ditch, a pole shall be installed at least 4.0 metres as a minimum back (dependent on traffic speed and slope of shoulder) of the existing road shoulder if possible.

At railway crossings, all poles should be located at least 3 metres from the nearest track or as required by the railway company. If possible, it is preferred to keep the crossing poles outside of the railway right-of-way.

In choosing the route of a pole line, trees should be avoided, where possible, to reduce the ongoing tree trimming costs and our exposure to outages caused by trees.

Every attempt should be made to locate new pole lines on municipal road allowances. Easements across private property should be avoided where possible. With property services, the customer owns the poles on their property unless there is an easement.

5.10 Overhead Transformers, Capacitors and Reclosers

Where possible, overhead transformer locations should be chosen to ensure a line truck can be used to change the transformer in the event of a failure.

It is preferred that transformers located in backyards can be seen from the street providing faster identification of fuse and transformer failures.

Transformer should be mounted on the pole in-line with the overhead conductors to achieve structural balance. For a three-phase cluster arrangement, the transformers should be positioned such that the centre transformer is in line with the overhead conductors.

Multi-pole stand (platform structure) may be used for voltage regulators, step transformers, and reclosers for dedicated distribution system requirements and only if these devices cannot be direct mounted to the pole. Such stands shall not be installed in the urban area, along major arterials, nor public or provincial highways. Stands shall not to be used for distribution transformers. Existing transformer stands should be removed upon failure or upgrade.

The maximum size of a pole-mounted transformer for both single-phase and three-phase (banked) applications is 100kVA.

Keep unsightly capacitor banks and line reclosers (Vipers) away from aesthetically sensitive areas.

Three-phase transformer cluster installations shall not be installed along the following areas for aesthetic considerations:

- Schedule B roads (major arterials);
- Highways;
- Residential neighbourhoods;
- Sensitive commercial / heritage areas;
- Rivers / canal, and;
- Parks, playgrounds, and school yards.

If a three phase overhead 347/600V supply is required in these sensitive areas, consideration shall be given to a single tank three phase transformer. Exception to the above noted locations are consolidating two existing transformer clusters into one, the City formally has scheduled the road for underground conversion within seven years, or it is the first pole in on a residential side street from the main street.

5.11 Grounding and Multi-Ground System Neutral

Grounding of non-current carrying structures, parts, and low voltage circuits, increases safety to the general public, operating personnel, and to Hydro Ottawa customers using electric services on their property.

Grounding system neutrals stabilizes the circuit potentials with respect to ground and provides a path for ground faults to aid in operation of over-current devices and secure prompt and reliable protective device operation (fuse, breaker, recloser, etc.).

In addition. grounding systems provide a path for lightning surges and reduce the likelihood of insulation failure in transformers, terminations, etc. Good grounding systems will also eliminate tingle voltage and minimize step and touch potentials.

The multi-grounded system neutral has the dual function of carrying load current and acting as a ground conductor. It is common to both secondary and primary distribution, and greatly improves grounding efficiency with the benefit of requiring one conductor instead of two.

On secondary systems, each customer’s local ground is connected through the service drop to the system neutral. Since the system neutral connects all customers’ grounds together it increases the safety of each individual installation, and forms a large continuous neutral grid with low resistance to ground.

However, this large ground grid may not be available in low-density rural areas or along primary circuits without secondary distribution. In these areas, neutral

multi-grounding is typically accomplished through the installation of ground rods at all pole mounted equipment locations and at regular intervals along the pole line.

The minimum neutral wire size is outlined in Section 6.6.

The minimum pole ground lead (ground rod to neutral) shall be #4 AWG stranded copper.

The minimum equipment ground conductor (equipment to neutral) shall be #4 AWG stranded copper.

A pole ground shall be installed at each pole with distribution equipment, primary cable risers or lightning arrestors.

The ground lead shall be protected with a plastic moulding or be RWU90 insulated conductor.

The standard grounding method for overhead systems shall be a [¾"x 10'] galvanized steel rod installed in undisturbed native soil. This may not be possible in all situations due shallow or rocky soil or along dense urban streets with crowded U/G utilities. Ground plates, 'butt coils', or remote grounding may be considered at these locations. Installation of ground rods at adjacent poles should be considered before 'butt coils' are installed.

A #4 Cu pole butt coil should only be used only in cases where a ground rod cannot be installed.

Ground rod minimum offset distance from a pole is 400 mm (+/- 200mm) due to localized ground shrinkage.

Grounding at the time of installation must measure less than 25 Ohms.

Multi-grounded system neutral should endeavour to be less than 6 ohm/km. This requires a minimum of one 25-ohm ground every 175 metres (Approximately 4 poles). The spacing may be increased in the event of lower (measured) ground resistance.

Overhead sky wires shall not be installed on the distribution system as they provide little, if any benefit, to distribution and sub-transmission voltage circuits in the Ottawa area.

5.12 Guying and Anchoring

Storm guying will be installed on every fifth pole (minimum) in large open areas (typically rural locations) depending on the number and type of conductors on the pole line. Locations where is there is good shelter from cross winds, such as urban areas) do not require storm guying. Where storm guying is impracticable, the tangent pole requiring additional strength is to have a minimum of one pole class stronger than the pole line and depth set to 20% length + 2'.

Down guys shall not cross other down guys. A coloured, highly visible yellow down guy guard is required in all areas.
Guys and anchors shall respect similar minimum offset distances in congested urban areas to those of poles.

Where more than one anchor is installed in the same alignment, they should be spaced a minimum of 1,500 mm apart.

Only as a last resort will buildings be used as anchors in congested urban areas. The following conditions must be satisfied before anchoring to a building:

The maximum structural loading on the building must be certified by a professional structural engineer;

Down guy insulators shall have at least double the insulation level to the highest circuit voltage, and;

An easement for the guying and anchor across the lands and to the building shall be acquired. The easement shall note that the building owner shall be responsible to maintain the structural integrity of the building to support the overhead electrical system structural loading.

Guying and anchoring to trees is not acceptable.

Push braces should be avoided in urban areas or along main arterial roadways.
With roads without a curb, an anchor shall be installed at least 4.0 metres as a minimum back (dependent on traffic speed and slope of shoulder) of the existing hard surface if possible.

5.13 Aesthetic Considerations

For designated traditional main streets or sensitive heritage/commercial areas, the following elements should be considered with rebuilds to improve the overhead system aesthetics:

- Limit the maximum number of primary circuits to two;
- Use spun secondary buses;
- Consolidate service drops with road crossing where possible;
- No cluster mount or banked transformers;
- No complex pole mounted three phase switches, voltage regulators, reclosures, or capacitor banks;
- Avoid mid-sidewalk, driveways, and front doors with pole and anchor locations;
- No pole mounted antennas, and;
- Ensure sufficient pole height is installed for street lighting fixtures and decorative banners.

6.0 Approved Materials

6.1 Poles

Hydro Ottawa's standard pole material for universal application is treated wood. This is due to its reasonable cost, climb-ability, and availability. Alternate materials such as composite and concrete can now be cost competitive and offer some unique benefits over traditional wood structures. Alternate materials like composite and concrete should be installed in situations where they will provide an overall decrease in total life cycle costs. This includes areas with wet soil and swamp like conditions where the in-situ environment is hostile to traditional wood structures. Alternatives should also be applied in areas where woodpeckers or insects have been known to damage poles.

The matrix below summarizes the application of wood, concrete and composite. There are some overlaps where a number of materials are permissible. Proper pole material selection will allow Hydro Ottawa to use each material in its best applications. In situations where different pole materials could be applied, the pole material with the most beneficial total life cycle costs should be considered.

	Suggested Application	Concrete	Wood	Composite
Low << Priority >> High	Temporary Pole Lines		X	
	Environmentally sensitive areas		Untreated	X
	Lines with no bucket access		X	
	Vehicle mechanical damage exposure		X	
	Areas prone to woodpecker damage	X		X
	Self support applications	X		
	Pole Replacement 65' and below		X	
	Pole Replacement 70' and up		X	X
	New construction 65' and below		X	
	New Construction 70' and up	X	X	X
	Aesthetic urban beautification paid by 3rd party	X		X

Table 1: Pole Material Application

6.1.1 Wood Poles

Wood poles are recommended for new construction [65'] and below.

Wood is ideal for locations that cannot be accessed by a bucket truck and must be climbed for regular maintenance activities

Standard wooden poles shall be full length treated CCA.

If the tops of all poles are "roofed" by the supplier to allow for water shedding and quick pole ownership identification, the pole shall be installed such that the roof ridge shall be in-line (parallel) with the main primary circuit.

Re-use of wooden poles shall be considered under the following parameters:

For full main trunk application: age < 15 years old for WRC and fully treated pine. Any other wooden pole type would be re-used with < 8 years service;

For secondary service clearance poles: age < 25 years old for WRC and fully treated pine.

Species: SYP and eastern cedar should not be re-used;

Type of treatment: untreated poles are not to be re-used; and Testing: The pole has no strength impairments (checks, holes, rot, scaling, mechanical damage).

6.1.2 Concrete Poles

Concrete poles offer an alternative excellent in heavy loading situations. However; due to their extreme weights, Hydro Ottawa line trucks cannot handle these poles and the use of a crane is necessary.

Concrete poles shall be a minimum of Class G and shall be limited to self-supporting applications and aesthetically sensitive areas.

When being considered for use in a "self-supporting" application, calculations must be performed to ensure the correct pole class is selected and a soil analysis should be performed to ensure adequate holding capacity. Concrete poles may be reused providing they show no physical signs of cracking, crumbling, damage or exposed rebar.

6.2 Composite Poles

Modular composite poles offer an advantage over wood in certain situations due to its high strength to weight ratio and resistance to rot and woodpecker damage.
They become economically competitive with wood in terms of overall life cycle costs for application [70'] and up.

Composite poles have a competitive up front and overall life cycle costs at 70' and higher.
Composite poles should be applied in areas where wood is prone to rot (wet soils, ditches and swampy areas), prone to woodpecker damage or environmentally sensitive areas where the installation of a treated wood pole is not appropriate (School yards, waterways).

Composite should also be considered in areas prone to pole fires.

Composite poles can also be an alternative to wood and concrete in aesthetically sensitive areas.

Re-use of composite poles is permitted. Re-cycled poles should be visually inspected for signs of damage.

6.3 Insulator Materials

Silicone insulators shall be the universal type; no porcelain or EPDM insulators are to be used except on the existing 4.16 kV system.

6.4 Fusing

SMD-20 fused cut-outs shall be used for cable risers under 200A and overhead transformer fusing on the 27.6kV system.

For distribution systems less than 15 kV, all fusing hardware shall be rated for 15 kV. CL (current limiting) fuses must be matched to the operating voltage.

6.5 Switches

Primary switches for risers shall use individual mounting bracket supports unless the switches are gang operated. This reduces inventory of common and individual mounting bracket supports and provides greater flexibility with mounting arrangements.

Any inline switches installed to allow for construction isolation are to be removed and changed to a compression connection at the completion of work unless otherwise directed by system office.

Line Tap style switches (Vegas) may be used in reduced clearance applications

6.6 Cross-Arm Materials

Wood cross-arms shall be used for the 4kV system (Douglas Fir) using the standard 4 pin, 6 pin and 4 pin special configurations. The dead-end cross-arm on the 4 kV system shall be the Aluma-4 Apitong wooden type.

For the other distribution voltages, wood, steel, or fibreglass dead end arms can be used with the steel arms being the standard 4” x 4” in 7.5’, 9.5’, and 22’ (double pole crossings) lengths.

Any other lengths or types needed for special applications shall be special ordered as required.

6.7 Primary and Neutral Conductor Sizes & Materials

3/0 ACSR (Pigeon), 336 kcmil AAC (Tulip), and 556 kcmil AAC (Dahlia) conductor is to be normally used for all new primary phase circuits (except for minor extensions within an existing system, where the existing wire size should be matched if available). Conductor larger than 556 kcmil may be considered under special circumstances to minimize voltage drop.
3/0 AACSR (on 3/0 primary) and 336 kcmil ACSR (Linnet) (on 556 kcmil AAC and 336 kcmil AAC primary) are to be used for system neutrals.

6.8 Secondary Buss Sizes & Materials

6.8.1 For120/240V Applications

Secondary buss conductors shall be 266 MCM aluminium, insulated at 600V. The 266 MCM buss conductors shall be over-lashed (field spun) onto either a 3/0 AACSR or 336 ACSR conductor. Secondary buss conductors may also be reduced to 3/0 aluminium insulated at 600V for lightly loaded rural applications. See OCM0001 and OCM0005.

Rebuilds in urban core areas may require factory spun 3/0 AACSR with 2-266 MCM aluminium buss conductors rated at 600V where access is difficult or obstructions with trees are prevalent. See OCM0003.

For small un-metered secondary services such as street lights, traffic signals, and Rogers or Bell equipment, 1/0 secondary triplex may be used for up to four spans. Prior to installation, a review of the present and future requirements should be undertaken to consider future capacity requirements for the area that the reduced buss size is to be installed. Where the un-metered service is more than 4 spans in length, field spun secondary bus shall be installed.

6.8.2 For 347/600V Applications

Secondary buss conductors shall be 3/0 aluminium, insulated at 600V. The 3/0 buss conductors shall be over-lashed (field spun) onto 3/0 AACSR conductor. Cable lashing machine size constraints do not permit over-lashing to336 ACSR.

6.9 Secondary Conductor Size Materials

Overhead triplex or quadruplex shall be used for all overhead secondary services. Depending on service size requested, #2, 1/0 or 3/0 AWG triplex or quadruplex conductor shall be used.

Only power installed wedge connectors are to be used on new service connections. Insulink compression connectors may not be used unless approved by the standards group.

6.10 Guying Materials

A minimum of Grade 180 10 mm [3/8”] guy steel shall be used for all guying applications.

Grade 180 12 mm [7/16”] guy steel may be used for custom engineered railway or highway crossings to meet CSA 22.3 No.1 standards where required.

Only epoxy or fibreglass guy strain insulators are to be used; no porcelain guy strain insulators shall be used.

Span guys and down guys are to be finished off using either 2-3 bolt clamps or a preformed guy grip.

6.11 Anchoring Materials

A minimum 254 mm [10"] single helix, power installed screw anchor (PISA) shall be installed to a minimum depth of 2.13 m [7'] on a 25 mm [1"] anchor rod with a double eye.

An equivalent strength anchoring device may be used in place of the PISA such as a double helix PISA, triple helix PISA (swamp), or expansion anchor with a 25 mm [1"] anchor rod with a double eye.

Guying and anchoring systems must be designed for the actual load and soil conditions. Charts and tables are available in GAS0001 to assist in calculating the maximum allowable guy tensions, and anchor holding capacities.

6.12 Steel Attachments

All steel parts on a pole shall be hot dip galvanized due to increased corrosion from CCA treated poles and the high salt concentrations on the Ottawa roads in winter.

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Overhead Design Guideline

REVISION SHEET

Revision	Description of Change	Date	Initial
0	Original Document	2003-05-12	ml/bb
1	General revision	2005-04-12	rm/csm
2	General revision & Pole materials	2006-03-08	rm/csm
3	Section 5.6, Grounding of Steel Arms	2009-01-10	cm/csm
4	Section 5.3, Pole Framing and Circuit Position	2009-05-12	cm/csm
5	Section 5.9, Local Control Devices, Added, General revision	2019-02-15	rw/mw
6	Section 6.1, Poles, Added, General revision	2024-01-24	ms,yb/mw
7	Section 5.6.1, Riser poles	2024-06-27	ms,yb/mw
8	Section 5.12, Guying and Anchoring & Section 6.2, Composite Poles	2024-11-01	ms,ml/mw
9	Added reference to ECP0017 and GEG0001. Modified section 5.4. to now have consultation with Asset Planning for 4 circuit constructions. Added section 5.5. Pole Replacement.	2025-07-21	ms,yb/mbw

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1. Introduction

This document outlines the general overhead distribution design philosophy to be used by Hydro Ottawa staff or contractors when designing and constructing Hydro Ottawa's overhead distribution system. These standards and practices will meet regulatory requirements and produce a cost effective, reliable, and maintainable overhead distribution system.

Prior to amalgamation, many predecessor utilities adopted the 1992 Ontario Hydro overhead standards manual as a general design guideline for constructing its overhead distribution system. Deviations from this manual were allowed to meet special or local circumstances. The 1992 Ontario Hydro standards manual was produced to primarily support a rural distribution system and not a combination rural/urban system similar to Hydro Ottawa.

This document will assist to develop, maintain, and update new overhead distribution construction. Where Hydro Ottawa standards do not exist, the Ontario Hydro Manual (1992) or specific pre-amalgamation utility standards shall be used until an in house standard is developed.

2. Reference

- CSA – C22.3 No. 1 – Overhead Systems.
- CSA – C22.3 No. 5.1 – Recommended Practices for Electrical Protection - Electric Contact Between Overhead Supply and Communication Lines.
- Hydro Ottawa – ECS0012 – Conditions of Service.
- Hydro Ottawa – GAS0001 – Overhead Standards Guying and Anchoring Engineering Specification
- Hydro Ottawa – GDS0014 – Negotiated Joint-Use Design and Installation Guideline Between Hydro Ottawa Limited and Hydro One Networks Inc.
- Hydro Ottawa – DFS0012 – Signing Authority for Technical Based Documents
- Hydro Ottawa – OPT0001 – Pole Selection Table for Wood Poles
- Hydro Ottawa – Various Overhead Distribution Standards.
- Municipal Electric Association – Guide to Municipal Standard Construction, Part 2 - Overhead, 1996.
- Ontario Electrical Safety Code.
- Ontario Hydro – Overhead Distribution Standards, 1992 Ed.
- Ontario Regulation 22/04 – Ontario Electrical Distribution Safety Code.
- Ottawa Hydro – Specifications for Overhead Line Construction 4kV & 12kV.
- Utilities Standards Forum – USF Standards
- Electrical Safety Authority - Distributor Bulletins [Link]
- Hydro Ottawa - ECP0017 - Economic Evaluation Procedure
- Hydro Ottawa - GEG0001 - Asset Health Index Guideline

3. Scope

This design guideline is intended to be used for the design of new overhead distribution plant, both greenfield and established urban and rural service areas while meeting Regulation 22/04 requirements.

4. Pre-amalgamation Utility Construction Standards (Legacy) and other Utility Standards

Hydro Ottawa has internal pre-amalgamation line construction standards from the predecessor utilities and have purchased the rights to use some external construction standards from the following groups:

1. Ontario Hydro, line construction standards prior to 2004 (now Hydro One Networks Inc. – referred to as HONI hereafter);
2. Mississauga Hydro, line construction standards posted on the intranet prior to 2002 (now Alectra);
3. USF Standards

The use of old construction standards will also depend upon availability of the older stocked items that may be depleted or no longer available.

5. Design Approach

There are often many possible solutions to any design problem. The purpose of this section is to provide an overall design philosophy to aid in the decision making process, and to encourage industry standard, “best practices”.

5.1. Hydro Ottawa Primary Voltages Boundaries by Area

Voltage boundaries may change due to loading, reliability, economics, accessibility, and/or specific problems. Where feasible, extensions and interconnections will be promoted to provide capacity sharing and improved contingency planning.

Area	Voltages (kV)
Ottawa	4.16, 13.2
Nepean	8.32, 13.8, 27.6, 44
Gloucester	8.32, 27.6, 44
Kanata	8.32, 12.47, 27.6, 44
Goulbourn	8.32, 27.6, 44
Casselman	8.32

Table 5-1: Area Primary Voltages

5.2. Equipment Insulation Levels

All equipment connected to the distribution system must meet or exceed the Basic Insulation Level (BIL) requirements shown in Table 5-2.

Voltage Level (kV)	BIL (kV)
4.16	60
8.32	95
12.47	95
13.2	95
27.6	125
44	250

Table 5-2: BIL Requirements

All new distribution line rebuilds are to accommodate 28 kV insulation as shown in Table 5-3, with the exception of spot replacement within the 4.16 kV system.

In order that we may improve system reliability, and minimize the number of stock items, the following guidelines will apply when selecting insulators:

Insulation Level	Insulation Levels
15 kV	4.16 kV Spot Replacement
28 kV	All Voltages 13.8 kV and below
46 kV	27.6 kV Primary
69 kV	44kV Primary
69 kV	44 kV dead ends and
69 kV	44kV system in a contaminated environment
69 kV	44kV primary on conductive poles

Table 5-3: Insulation Levels

5.3. Circuit Position

Pole framing for multiple circuits of unlike distribution voltages or a combination of sub-transmission and distribution voltages shall consider the separation criteria outlined in this section.

5.3.1. Vertical Separation of Different Voltages

Vertical separation of unlike distribution voltages or a combination of sub-transmission and distribution voltages shall be framed having the highest voltage at the highest level on the pole.

44 kV sub-transmission circuits shall not be installed at the same level on a pole as any 13.2 kV sub-transmission circuit.

44 kV and 13.2 kV sub-transmission circuits shall not be installed at the same level on a pole as any other distribution circuit.

It should be noted that legacy standards typically called for higher voltages to be framed higher on the pole; however, that isn't required anymore.

5.4. Pole Height, Strength, and Spacing

The pole height, strength, and spacing shall be determined using the following and OPT0001.

Geometric non-linear analysis is required by CSA 22.3 No. 1 when designing pole lines to verify the strength of supporting systems, such as poles, guys and anchors; such analysis shall be done using the software application SpidaCalc. Refer to OLS0006 for a list of SpidaCalc Client File contents.

CSA overhead standard C22.3 No.1 will be used to determine vertical clearances over roads, highways, railways, navigable waterways, etc.

System neutral is to be normally installed at 7.6 m [25'] minimum (parallel & perpendicular) above all roadways. This clearly sets the reference height for telecommunication companies as per OLS0001.

Improved appearance (armless) construction is preferred with new construction projects.

Vertical construction is encouraged to facilitate the future installation of an additional circuit(s).

For new construction, the maximum number of three phase circuits per pole shall be 4 and 4 circuit construction shall be consulted with Asset Planning.

Secondary buses, services, and neutrals shall be attached below transformers.

Pole heights and class shall be based on Hydro Ottawa standard OPT0001. Choice of pole depends on the number of circuits and span lengths. The location of the poles should also be considered when choosing pole classes. Class 2 poles are preferable for the central area of Ottawa due to space restrictions, however, class 1 poles can be installed elsewhere in the distribution territory when OPT0001 specifies for class 2 poles to assist with storm hardening and simplify pole storage.

Pole spacing should vary to dampen conductor gallop.

A vertical maximum of 5’ fibreglass pole extension shall only be used on an existing pole where strength or aesthetics are not a requirement.

Along major arterials and other aesthetic sensitive areas, alley arms should be avoided.

Adequate vertical space between circuits must be available for access by aerial devices. A minimum 1.5 m [5’] vertical space must also be available between circuit phases on pole lines well off the travelled portion of the road or where access by aerial devices to the field side of the pole is restricted.

1.8m [6’] vertical space shall be left between 44kV sub-transmission and lower primary distribution voltages.

Along major arterials and other aesthetic sensitive areas, poles should not be stepped in line with the existing pole line if 20-metre separation between poles cannot be achieved. Re-arrange the overhead equipment to obtain the required aerial real estate for a new/upgraded customer connection.

5.5. Pole Replacement

If the project is customer driven and the health index of poles is 50% or less as per GEG0001, consider pole replacement. Advancement costs to be prepared as per Economic Evaluation Procedure ECP0017.

For projects that are Hydro Ottawa driven and the health index of poles is 50% or less as per GEG0001, consider pole replacement through the regular testing and review process with Maintenance & Reliability.

5.6. Third Party Plant on Poles

Third party’s or approved contractors shall not carry out work on/in Hydro Ottawa support structures (ex. poles, manholes, handholes) without approval from Hydro Ottawa.

In no case shall third party’s or its contractor’s work on Hydro Ottawa poles above any live conductor, install an underground service on a pole or in a manhole/handhole where Hydro Ottawa cable is present. Moreover, Safe Limits of Approach as specified in the EUSR Rulebook shall apply. Refer to GQS0008 for further information.

A pole attachment agreement will be required for all telecommunication equipment, third party boxes, street lighting, and occasional decorative banners & lights. Exceptions may be granted for small secondary electrical disconnects (≤ 100 A), non-electric traffic signage, non-electric bus stop signs, poster collars, and mail boxes.

5.6.1. Telecommunications

A 600mm telecommunication corridor is outlined in Hydro Ottawa Standard OLS0001. This telecommunication space allows a maximum of 3 parallel, vertically mounted (no offset brackets) telecommunications support strands 300 mm apart on the same side of the pole. Some locations may be restricted to fewer or no communication strands due to height restrictions, pole strength, or aesthetics, or the age of the pole. Telecommunication attachments should try to overlash where possible.

Telecommunication support strands on poles with primary circuits shall be bond to a grounding system at a maximum of every 300 m as per CSA standard C22.3 NO. 5.1.

Third party boxes e.g. power supplies, amplifiers, antennas etc. shall be mounted below the telecommunication space (see OLS0001 and OLS0008). Antennas and third party non-electrical supply boxes shall not be installed within one pole span of critical crossings (such as railways, waterways, highways, transit ways, cliffs). The 15 metre sight line triangle at all public road intersections, turning islands, and road way mediums shall be kept clear of any antennas. Antennas shall not be within 100 meters of other pole mounted antennas and non-electrical supply boxes. Antennas and non-electrical supply boxes shall not be installed within ±60 degrees from perpendicular to commercial building signs.

Parallel telecommunication support strands shall not cross over one another between poles.

Telecommunication companies shall not install riser cables on poles that have more than 33% of the circumference [120 degrees] taken up with existing riser cables and cable protection (guards, duct laterals and concrete curbs).

When pole replacements occur, it is common practice to cut the existing pole above the telecommunication strands to create an in-span pole butt that will remain until the telecommunication owners transfer their equipment to the new pole. In-span poles pole butts that only hold telecommunications strands and no supply conductors shall only remain for two years after the start of the pole replacement project, given that the following conditions are met:

- Mechanical protection, agreed upon by all attachers, is installed on the in-span pole to create a safe work environment for the workers unless the separation between the top of the in-span pole butt and the highest telecommunications attachment point is between 100mm to 200mm
- Minimum in-span clearances between the telecommunications attachment and the un-supported supply plant are 1000mm for supply plants less than 750V, 2500mm for supply plants greater than 750V and less than 22kV and 3600mm + 0.01m/kV for supply plants over 22kV.
- New pole is installed within 3m of the in-span pole butt’s location

Agreements shall be considered when working with telecommunications attachments.

5.6.2. Street Lighting

In urban areas and along major arterial roads, sufficient height and inter-pole spacing shall be available for future roadway street lighting. Where possible, re-alignment of anchoring stub poles to accommodate street lighting luminaries shall also be considered to reduce pole congestion and aesthetics concerns.

Streetlight continuous pole lines shall not be installed within 5.0 m parallel to primary conductors to reduce pole congestion and aesthetics concerns.

For third party worker safety, streetlight, telecommunication, and traffic poles shall not be installed within 3.5 m of primary conductor and 1.5m of secondary or neutral conductor without written permit approval. Please refer to OLS0003 for more information.

Overhead electrical service wire can be temporarily (up to one year) installed to service a street light pole and luminaire from a Hydro pole until the normal underground street light service wire is repaired.

5.7. Riser Poles

5.7.1. General

For reliability, install only one primary trunk or station feeder egress riser per pole. In dense urban areas, two primary 3-phase service risers may be allowed on a single pole if there is no practical alternative.

Poles accessible by bucket trucks may have riser(s) covering more than ⅓ the circumference of the pole. Where bucket access is not feasible,the pole shall not have more than ⅓ the circumference of the pole with riser(s) to allow for pole maintenance and space to climb if required.

All primary risers shall be guarded from the base of the pole to no less than 200 mm below the neutral. Refer to UJS0567/UJS0569 for clarity.

Guards shall make direct contact to the pole (no offset). All primary underground service risers on poles shall have a reinforced, poured concrete curb for protection where required.

Electrical risers shall be installed on the side of the pole opposite (downstream) to traffic flow where possible for system protection.

A pole ground shall be installed at all primary riser locations.

No permanent secondary metering shall be installed on utility owned poles.

Only contractors qualified by Hydro Ottawa or utilities with a Municipal Access Agreement shall attach to Hydro Ottawa owned support structures.

Electrical connections onto Hydro Ottawa owned support structures shall meet Hydro Ottawa cable standards e.g. no metal sheath cables such as teck, pyro, or coreflex.

5.7.2. Primary Riser Poles

The primary cables shall rise up the pole and be terminated below the lowest circuit, with the exception of sub-transmission risers where the riser shall terminate immediately below the associated circuit.

All connections onto the primary conductor greater than 200 Amp shall be power installed wedge type connectors.

Connections to the primary conductor less than or equal to 200 Amp shall be made via stirrup and hot line clamp. Connections made to copper primary conductor can be made with a copper hot line clamp directly

Connections less than 200A shall be fused with the exception of the Ottawa 13.2 kV Sub-Transmission and 44kV sub-transmission.

Connections greater than 200A will be made with solid blade switches or line tap switches.

Lightning arrestors shall be installed at all riser locations and shall be connected to the multi-ground system neutral. See GDS0011. A pole ground shall be installed at all riser locations. The impedance shall be measured and verified less than 25 ohms.

5.7.3. Pothead Primary Riser Poles (Legacy)

Any lead cable applications utilizing pothead construction shall not be installed as new, and existing applications are to be removed and replaced with current standards.

5.7.4. Secondary Riser

All secondary risers shall be in conduit complete with a weather head up to the secondary power space on the pole. The drip loops of the secondary conductors shall be no greater than 200mm below the neutral. The weatherhead shall be at or above neutral.

For an underground service on a utility owned pole, the service head shall not be less than 1500 mm [59”] above the telecommunication equipment. In every case the contractor shall obtain instructions from Hydro Ottawa before installing the cable on the pole.

All services greater than 200 A (including a temporary service) shall leave the pole by an underground riser. Concrete laterals shall be site specific, however, no concrete laterals shall be installed in backyards.

5.8. Overhead Equipment Location Considerations

For safety and reliability, the following location and distance offsets should be taken into consideration.

For new construction, no primary or secondary conductors over swimming pools (see Conditions of Service, Section 3.0).

New permanent structures (that are ‘normally’ occupied such as houses, garages, buildings, buildings with balconies, mobile trailer homes, pedestrian bridges) shall not be located within the safe limits of approach. Refer to OLS0002 and GAS0005 (for <46kV, it is 3 meters from the maximum outward conductor swing) and an additional 2 meters for building maintenance (such as painting, roofing, window washing, brick pointing); this would result in a minimum of 5 meter radial separation from the closest primary phase conductor.

In addition, every attempt shall be made to keep existing buildings at least 2 meters horizontally outside of the closest primary phase conductor with respect to the vertical plane (from the ground to the primary phase conductor).

On an individual (case-by-case) basis, portable and temporary (less than 1 year) structures such as garden sheds < 100 ft-sq and construction trailers may be installed directly under primary conductors where there is sufficient height clearance (3 m vertically plus 2m for a person standing on top of the temporary structure) and the structure is grounded (minimum of <25 ohms with a #4 AWG Copper conductor to a 3 meter ground rod) although a reasonable attempt should be made to avoid such arrangements.

Primary risers and distribution transformers are to be kept away from intersections. If equipment is forced towards an intersection, priority shall be given to keep primary risers away from intersections versus distribution transformers.

Fuses and switches should be positioned on the pole for ease of operation and maintenance. The choice of location/position must consider safety (aerial device set-up, possible equipment failure during operation, etc.).

To reduce the possibility of pole fires, composite cross arms should be used. Where steel cross arms are installed, they shall be bonded to ground when conductors are connected via porcelain or glass insulators. Where conductors are connected to a steel arm via silicone or polyethylene insulators, it is not necessary to bond the arm to ground.

In-line switches, fuses, or mid-span openers shall not be located over railways, transit ways, roadways, or navigable waterways.

In urban areas having no ditches, all primary service road crossings will be underground.

In urban areas having no ditches, all secondary services greater than 200A will be underground.

Overhead secondary services can be unsupported in length up to 38 meters from the supply pole to the standpipe. Any overhead spans greater than 38 meters will require a service pole to be stepped-in or a reinforced standpipe installed.

Electrical switch operating handles shall be installed on the side of the pole opposite (downstream) to traffic flow where possible for system protection.

Utility devices that locally control the aerial primary equipment can be mounted reasonably low as possible if the device is motor/manually operated (refer to OSS0403/OSS0301), else the device shall be 2440mm above grade (refer to OSS0307) in non-sensitive commercial / heritage / residential areas. Such devices that are located at grade level shall be protected from harm (eg. snow plows, vehicles, etc.), not interfere with pedestrian or traffic flow, and have adequate safeguards to ensure public safety.

5.9. Environmental Considerations for Chemically Treated and Oil Filled Equipment

Every attempt shall be made to keep wooden poles treated with CCA preservative away from schoolyards, playgrounds, and open waterways. Other approved pole materials should be considered in these circumstances. Pentachlorophenol wood treatment shall not be used under any circumstances.

Oil filled equipment shall not be installed within 15m of open waterways unless there is a dedicated oil containment facility where practical.

Oil filled distribution transformers are to be kept away from intersections unless there is no other option. Primary risers take precedence over transformers (see section 5.6).

5.10. Pole Location Considerations

The total number of poles (Hydro, Bell, street lighting) should be minimized. This requires joint planning and construction along the road allowance. Parallel pole lines on opposite sides of the street should be avoided unless the roadway is at least 6 lanes wide.

It should be assumed that all intersections will at some time be modified by the road authority so all attempts should be made to install poles 3 meters from the intersection curbs and use ‘flying taps’ to make electrical connections at the corner. This will also reduce the exposure to vehicle accidents, especially with composite poles which can buckle.

A pole installed in small medians (< 6 m wide) or turning islands in the roadway should be avoided where possible.

In urban areas, no overhead transformers, primary risers, or secondary service risers >200A @ 240V shall be located within the 15 meter sight line triangle of intersections or major commercial entrances with curbs due to the greater chance of vehicle accidents and the difficulty of blocking both streets to do any maintenance work. Spacing to other above ground utilities should be considered as per OLS0003.

Poles should be located so as not to obstruct doorways, fire hydrants, or driveway entrances.

In existing urban areas, poles located along curb lines shall be set so that there is a minimum of 500 mm, where possible, between the nearest surface of the pole and the roadside curb / sidewalk. This will reduce damage during snow removal operations and allow city bus operations. In tight offset locations (<500 mm), [¼"] steel plate shall be used to protect the pole from snow plow damage, and protective bollards may be required to protect low mounted switching handles.

Protective bollards will guard Hydro Ottawa primary circuit carrying poles that are exposed (ex. no curbs) and located in the middle of major parking lots where vehicle speeds of > 20 km/h can be easily achieved.

In urban areas without a curb on an existing roadway, a pole is preferred to be installed at least 4.0 meters as a minimum from the edge of the drive lane (dependent on traffic speed and slope of shoulder) of the existing hard surface, including bike paths, if possible.

Typically in rural areas, the poles are to be installed a minimum of 1.5 meters off property line. An offset from the property line greater than 1m may be required to prevent wires overhanging private property due to the use of larger pole hardware such as brackets and insulators. Installing poles at the bottom of the roadway ditch should be avoided.

At railway crossings, all poles and anchors should be located outside the rail right of way, unless agreed upon by the rail authority.

In choosing the route of a pole line, trees should be avoided, where possible, to reduce the ongoing tree trimming costs and our exposure to outages caused by trees.

Every attempt should be made to locate new pole lines on municipal road allowances. Easements across private property should be avoided where possible. With property services, the customer owns the poles on their property unless there is an easement.

Pole shall be installed based on the detail outlined in OPS0205.

5.11. Overhead Transformers, Capacitors and Reclosers

Where possible, overhead transformer locations should be chosen to ensure a line truck can be used to change the transformer in the event of a failure.

It is preferred that transformers located in backyards can be seen from the street providing faster identification of fuse and transformer failures.

Transformer should be mounted on the pole in-line with the overhead conductors to achieve structural balance. For a three-phase cluster arrangement, the transformers should be positioned such that the center transformer is in line with the overhead conductors.

Multi-pole stand (platform structure) may be used for voltage regulators, step transformers, and reclosers for dedicated distribution system requirements and only if these devices cannot be directly mounted to the pole. Such stands shall not be installed in the urban area, nor public or provincial highways. Stands shall not be used for distribution transformers. Existing transformer stands should be removed upon failure or upgrade.

The maximum size of a pole-mounted transformer for single phase is 167kVA and three-phase (banked) applications is 100kVA.

Keep capacitor banks and line reclosers away from aesthetically sensitive areas.

Three-phase transformer cluster installations are not preferred to be installed along the following areas for aesthetic considerations:

- Schedule B roads (major arterials);
- Highways;
- Residential neighborhoods;
- Sensitive commercial / heritage areas, and;
- Parks, playgrounds, and school yards.

Note: Three-phase transformer cluster installations shall not be installed along rivers/canals.

If a three phase overhead 347/600V supply is required in these sensitive areas, consideration shall be given to a single tank three phase transformer if available. Exceptions to the above noted locations are consolidating two existing transformer clusters into one, the City formally has scheduled the road for underground conversion within seven years, or it is the first pole in on a residential side street from the main street.

5.12. Grounding and Multi-Ground System Neutral

Grounding of non-current carrying structures, parts, and low voltage circuits, increases safety to the general public, operating personnel, and to Hydro Ottawa customers using electric services on their property.

Grounding system neutrals stabilizes the circuit potentials with respect to ground and provides a path for ground faults to aid in operation of over-current devices and secure prompt and reliable protective device operation (fuse, breaker, recloser, etc.).

In addition, grounding systems provide a path for lightning surges and reduce the likelihood of insulation failure in transformers, terminations, etc. Good grounding systems will also eliminate tingle voltage and minimize step and touch potentials.

The multi-grounded system neutral has the dual function of carrying load current and acting as a ground conductor. It is common to both secondary and primary distribution, and greatly improves grounding efficiency with the benefit of requiring one conductor instead of two.

On secondary systems, each customer’s local ground is connected through the service drop to the system neutral. Since the system neutral connects all customers’ grounds together it increases the safety of each individual installation, and forms a large continuous neutral grid with low resistance to ground.

However, this large ground grid may not be available in low-density rural areas or along primary circuits without secondary distribution. In these areas, neutral multi-grounding is typically accomplished through the installation of ground rods at all pole mounted equipment locations and at regular intervals along the pole line.

The minimum neutral wire size is outlined in Section 6.6.

The minimum pole ground lead (ground rod to neutral) shall be #4 AWG copper.

The minimum equipment ground conductor (equipment to neutral) shall be #4 AWG stranded copper for overhead transformers, or 1/0 copper for equipment other than overhead transformers.

A pole ground shall be installed at each pole with distribution equipment, primary cable risers or lightning arrestors.

The ground lead shall be protected with a galvanized steel cable guard.

The standard grounding method for overhead systems shall be a [¾"x 10'] galvanized steel rod installed in undisturbed native soil. This may not be possible in all situations due shallow or rocky soil or along dense urban streets with crowded U/G utilities. Ground plates or remote grounding may be considered at these locations. Installation of ground rods at adjacent poles should be considered before 'butt coils' are installed. Refer to GDG0014.

A ground butt plate and conductive material should only be used only in cases where a ground rod cannot be installed, such as dense urban areas.

Ground rod minimum offset distance from a pole is 400 mm (+/- 200mm) due to localized ground shrinkage, unless there is a pole hole sleeve. Refer to OGS0001.

Grounding at the time of installation must measure less than 25 Ohms.

Multi-grounded system neutral should endeavor to be less than 6 ohm/km. This requires a minimum of one 25-ohm ground every 175 meters (Approximately 4 poles). The spacing may be increased in the event of lower (measured) ground resistance.

Overhead sky wires shall not be installed on the distribution system as they provide little, if any benefit, to distribution and sub-transmission voltage circuits in the Ottawa area. After confirming that there is a neutral conductor in place, existing sky wires should be removed where possible.

Note: If sky wire cannot be removed, do not connect it to the system neutral, leave it floating.

For station egress, refer to GDG0014.

5.13. Guying and Anchoring

Please refer to GAS0001 for guying and anchoring guidelines.

Storm guying will be installed on every fifth pole (minimum) in large open areas (typically rural locations) and on lines with high customer count to provide anti-cascading protection and resiliency. Locations where there is good shelter from cross winds (such as urban areas) do not require storm guying.

Wood poles should be used for storm guying. Depending on the number and type of conductors on the pole line, number of customers, as well as voltage, and for north-south lines, more frequent storm guying or composite poles with storm guying can be considered. Refer to OAS0005 for storm-guying framing.

Where storm guying anchor space is limited, the following may be considered:

1. Composite poles with reduced lead lengths. (Note: Despite its high strength, composite only pole lines should still have storm guying to reduce lean and potential cascading).
2. For wood poles, one class higher pole set to 20% length + 610 mm [2'] with reduced lead lengths.
3. Underground construction for pole lines and for priority customers (such as hospitals, pumping stations, police, fire, shelters, etc.) This will require discussions with the customer and/or Asset Planning.

Down guys shall not cross other down guys. A coloured, highly visible yellow down guy guard is required in all areas.

Guys and anchors shall respect similar minimum offset distances in congested urban areas to those of poles.

Where more than one anchor is installed in the same alignment, they should be spaced a minimum of 1,500 mm apart.

Only as a last resort will buildings be used as anchors in congested urban areas. The following conditions must be satisfied before anchoring to a building:

- The maximum structural loading on the building must be certified by a professional structural engineer;
- Down guy insulators shall have at least double the insulation level to the highest circuit voltage, and;
- An easement for the guying and anchor across the lands and to the building shall be acquired. The easement shall note that the building owner shall be responsible to maintain the structural integrity of the building to support the overhead electrical system structural loading.

Guying and anchoring to trees is not acceptable.

Push braces should be avoided in urban areas or along main arterial roadways, unless the installation is temporary.

With roads without a curb, an anchor shall be installed at least 4.0 metres as a minimum back (dependent on traffic speed and slope of shoulder) of the existing hard surface if possible.

Strut guys can be installed to increase clearance across pathways, please refer to OAS0006.

Where anchor space is limited, the following may be considered:

1. Use of stub pole for bisecting angle changes.
2. Use of span guys where there is no room for dead end anchoring.
3. A higher class pole set to 20% length + 610 mm [2’] with reduced anchor lead length.
4. Underground construction for tight sections.

5.14. Aesthetic Considerations

For designated traditional main streets or sensitive heritage/commercial areas, the following elements should be considered with rebuilds to improve the overhead system aesthetics:

- Use spun secondary buses;
- Consolidate service drops with road crossing where possible;
- Cluster mount, banked or power pack transformers are preferred;
- Avoid mid-sidewalk, driveways, and front doors with pole and anchor locations;
- Ensure sufficient pole height is installed for street lighting fixtures and decorative banners as per OLS0004.

6. Approved Materials

6.1. Poles

Hydro Ottawa’s standard pole material for universal application is treated wood. This is due to its reasonable cost, climb-ability, and availability. Alternate materials such as composite and concrete can now be cost competitive and offer some unique benefits over traditional wood structures. Alternate materials like composite and concrete should be installed only in situations where they will provide an overall decrease in total life cycle costs. This includes areas with wet soil and swamp like conditions where the in-situ environment is hostile to traditional wood structures. Alternatives should also be applied in areas where woodpeckers or insects have been known to damage poles.

The matrix below summarizes the application of wood, concrete and composite. There are some overlaps where a number of materials are permissible. Proper pole material selection will allow Hydro Ottawa to use each material in its best applications. In situations where different pole materials could be applied, the pole material with the lowest total life cycle costs should be considered.

Suggested Application		Concrete	Wood	Composite
Low << Priority >> High	Temporary Pole Lines		X	
	Environmentally sensitive areas			X
	Lines with no bucket access		X	
	Vehicle mechanical damage exposure		X	
	Areas prone to woodpecker damage	X		X
	Pole Replacement 65' and below		X	X
	Pole Replacement 70' and up		X	X
	New construction 65' and below		X	X
	New Construction 70' and up	X	X	X
	Self-supporting applications			
	Aesthetic urban beautification paid by 3rd party	X		X

Table 6-1: Pole Material Application

6.1.1. Wood Poles

Wood is ideal for locations that cannot be accessed by a bucket truck and must be climbed for regular maintenance activities

Re-use of wooden poles is not preferred, but shall be considered under the following parameters:

- For full main trunk application: age < 15 years old for WRC and fully treated pine. Any other wooden pole type would be re-used with < 8 years service;
- For secondary service clearance poles: age < 25 years old for WRC and fully treated pine.
- Type of treatment: untreated poles are not to be re-used; and Testing: The pole has no strength impairments (checks, holes, rot, scaling, mechanical damage).
- Financial reasons

6.1.2. Concrete Poles

Concrete poles offer an alternative excellent in heavy loading situations. However; due to their extreme weights, Hydro Ottawa line trucks cannot handle these poles and the use of a crane is necessary.

Concrete poles shall be a minimum of Class G and shall be limited to self-supporting applications and aesthetically sensitive areas.

When being considered for use in a "self-supporting" application, calculations must be performed to ensure the correct pole class is selected and a soil analysis should be performed to ensure adequate holding capacity. Concrete poles may be reused providing they show no physical signs of cracking, crumbling, damage or exposed rebar.

The life cycle costs of a self-supporting concrete pole are generally much higher than other material options due to manufacturing, delivery, and installation costs.
Thus, self-supporting applications requiring concrete poles should be considered as the last option available for use in pole lines.

6.2. Composite Poles

Modular composite poles offer an advantage over wood in certain situations due to its high strength to weight ratio and resistance to rot and woodpecker damage.

Composite poles should be applied in areas where wood is prone to rot (wet soils, ditches and swampy areas), prone to woodpecker damage or environmentally sensitive areas where the installation of a treated wood pole is not appropriate (School yards, waterways). Composite poles can be used for storm-guying, as discussed in section 5.12.

Composite should also be considered in areas prone to pole fires and high contamination from salts (such as highways), however caution should be taken installing composite poles close to high-traffic roads due to risk of buckling if a vehicle were to hit the pole.

Re-use of composite poles is permitted. Re-cycled poles should be visually inspected for signs of damage.

Due to the high cost of composite poles, composite-only pole lines should be discussed with Asset Planning and/or the customer. Should a composite-only pole line be selected, storm guying should still be used despite it's high strength as leaning can occur. Section 5.12 refers to anti-cascading solutions.

6.3. Insulator Materials

Silicone insulators shall be the universal type; no porcelain or EPDM insulators are to be used except on the existing 4.16 kV system.

6.4. Fusing

On the 27.6 kV system, SMU-20 fused cut-outs shall be used for cable risers under 200A and overhead transformer fusing.

For distribution systems less than 15 kV, all fusing hardware shall be rated for 15 kV. CL (current limiting) fuses must be matched to the operating voltage.

6.5. Switches

Primary switches for risers shall use individual mounting bracket supports unless the switches are gang operated, refer to URS0070. This reduces inventory of common and mounting bracket supports and provides greater flexibility with mounting arrangements.

Any temporary inline switches installed to allow for construction isolation are to be removed and changed to a compression connection at the completion of work unless otherwise directed by the system office.

Line Tap style switches (Vegas) may be used in reduced clearance applications.

6.6. Cross-Arm Materials

Composite dead end arms can be used with the steel arms being the standard 4" x 4" in 7.5', 9.5', and 22' (double pole crossings) lengths. Steel may also be used where required.

Any other lengths or types needed for special applications shall be special ordered as required.

6.7. Primary and Neutral Conductor Sizes & Materials

556 kcmil AAC (Dahlia) conductor is to be normally used for all new primary phase trunk circuits (except for minor extensions within an existing system, where the existing wire size should be matched if available). 3/0 ACSR (Pigeon) and 336 kcmil AAC (Tulip) may be used for specific applications, refer to OCM0001 and OCM0002. Conductors larger than 556 kcmil may be considered under special circumstances to minimize voltage drop.

3/0 AACSR (on 3/0 primary) and 336 kcmil ACSR (Linnet) (on 556 kcmil AAC and 336 kcmil AAC primary) are to be used for system neutrals.

Refer to GAS0002 for conductor properties.

6.8. Secondary Buss Sizes & Materials

6.8.1. 120/240V Applications

Secondary bus conductors shall be 266 MCM aluminium, insulated at 600V. The 266 MCM bus conductors shall be over-lashed (field spun) onto either a 3/0 AACSR or 336 ACSR conductor.

Rebuilds in urban core areas may require factory spun 3/0 AACSR with 2-266 MCM aluminium bus conductors rated at 600V where access is difficult or obstructions with trees are prevalent. See OCM0003.

For small un-metered secondary services such as street lights, traffic signals, and Rogers or Bell equipment, 1/0 secondary triplex may be used for up to **four spans**. Prior to installation, a review of the present and future requirements should be undertaken to consider future capacity requirements for the area that the reduced bus size is to be installed. Where the un-metered service is more than 4 spans in length, field spun secondary bus shall be installed.

6.8.2. 347/600V Applications

Secondary bus conductors shall be 3/0 aluminium, insulated at 600V. The 3/0 bus conductors shall be over-lashed (field spun) onto 3/0 AACSR conductor. Cable lashing machine size constraints do not permit over-lashing to336 ACSR.

6.9. Secondary Service Conductor Size Materials

Overhead triplex or quadruplex shall be used for all overhead secondary services. Depending on service size requested, #2, 1/0 or 3/0 AWG triplex or quadruplex conductor shall be used, refer to EMT0004.

Only power installed wedge connectors are to be used on new service connections.

6.10. Guying Materials

A minimum of Grade 180 10 mm [3/8"] guy steel shall be used for all guying applications.

Grade 180 12 mm [7/16”] guy steel may be used for custom engineered railway or highway crossings to meet CSA 22.3 No.1 standards where required, or other applications as required.

No porcelain guy strain insulators shall be used.

Span guys and down guys are to be finished off using either 2-3 bolt clamps or a preformed guy grip.

6.11. Anchoring Materials

Anchors shall be installed at a minimum depth of 2.13 m [7'] on a 25 mm [1"] anchor rod with a double eye.

Double helix PISA is preferred, however, where limited by utilities or ground conditions an expansion anchor with a 25 mm [1"] anchor rod with a double eye or tough single helix (ie: tree roots) may be used.

Guying and anchoring systems must be designed for the actual load and soil conditions. Charts and tables are available in GAS0001 to assist in calculating the maximum allowable guy tensions, and anchor holding capacities.

6.12. Steel Attachments

All steel parts on a pole shall be hot dip galvanized due to increased corrosion from CCA treated poles and the high salt concentrations on the Ottawa roads in winter.

Storm Hardening Study

Prepared By: Megan Lawton **Issue Date:** February 22, 2023

1. Introduction

Severe storms in Hydro Ottawa's distribution territory and predicted climate change in the near future has triggered HOL to look into storm-hardening solutions to prevent outages when storms occur. HOL's Overhead Design Guideline (GDS0003 - reaffirmed 2019) calls for storm guying every fifth pole in large open areas. Storm guying is typically side guying on both sides of the pole (see OAS0005, attached), but if storm guying is impracticable due to space constraints, the tangent pole requiring additional strength is to have a minimum of one pole class stronger than the pole line and to be set deeper into the ground.

As seen in most recent storms, a more robust option must be added to the above storm hardening criteria. A common solution seen across the industry is using a composite pole as the tangent pole requiring additional strength. Composite poles are much stronger than HOL's standard western red cedar pole but are at an increased price tag.

The following high-level study explores the above noted storm hardening criteria on a worst case pole line (North/South) to compare its performance in the current worst case scenario (currently used in structural calculations for HOL pole lines), the worst case weather conditions and in the weather conditions seen during the May 2022 Derecho.

2. Methodology

To justify using composite poles as a storm hardening solution, we performed a non-linear loading analysis study on one of the pole lines that was hit hardest during the May 2022 Derecho:

- Location: Greenbank Road between Hunt Club and Fallowfield
- Pole line direction: North/South
- Number of poles modelled: 39
- Pole line height(s): Varying between 40ft to 70ft
- Pole material: Existing pole line consists of a mixture of western red cedar and red pine poles
- Framing details:
    - OFS1330 (on all poles for ease of modelling)
    - 44kV (top two circuits): 556 ASC
    - 8.3kV (bottom circuit): 336 ASC
    - Neutral: 3/0 ACSR
    - Included worst case telecommunication attachments of three heavy bundles

Four storm hardening solutions on every 5th pole was considered, that being storm guying, increasing the wood pole class with a lower setting depth, using a composite pole alone and using a composite pole with storm guys. These four solutions were then compared to determine the storm support pole stress at the CSA Heavy weather case (as per CSA standards this is currently considered the worst-case weather loading and what is used in non-linear analysis for guying and anchoring in compliance with CSA 22.3 - January 2022 revision), the maximum allowable wind speed and ice thickness per solution and at the derecho wind levels, as summarised below. It should be noted that the CSA Heavy, maximum allowable wind speed and maximum allowable ice thickness was simulated on one pole (L17) for ease of modelling due to several iterations required to determine the maximum weather loading case per solution.

Solution	Storm Hardening Solution*	Weather Loading Case
A.1	Storm Guying	CSA Heavy
A.2	Storm Guying	Maximum allowable wind speed
A.3	Storm Guying	Maximum allowable ice thickness
A.4	Storm Guying	Derecho wind levels
B.1	Increased wood pole class	CSA Heavy
B.2	Increased wood pole class	Maximum allowable wind speed
B.3	Increased wood pole class	Maximum allowable ice thickness
B.4	Increased wood pole class	Derecho wind levels
C.1	Composite pole	CSA Heavy
C.2	Composite pole	Maximum allowable wind speed
C.3	Composite pole	Maximum allowable ice thickness
C.4	Composite pole	Derecho wind levels
D.1	Composite pole with storm guying	CSA Heavy
D.2	Composite pole with storm guying	Maximum allowable wind speed
D.3	Composite pole with storm guying	Maximum allowable ice thickness
D.4	Composite pole with storm guying	Derecho wind levels

*Storm hardening solution is applied to every 5th pole in the pole line as per GDS0003. This pole is referred to in the following table as the storm support pole.

3. Results

The table below summarises the findings of the study. Each maximum weather case was performed on a single storm support pole to determine the maximum wind and ice loading at failure (as close to 100% pole stress as possible), up to the derecho storm loading.

Solution	Weather Loading Case*	Storm Support Pole Stress
A.1	CSA Heavy	54.9%
A.2	195 km/h wind	101.5% Note: guys fail at 145 km/h wind (57.5% pole stress)
A.3	2.8 cm ice thickness	98.7% Note: guys fail at 2 cm ice thickness (73% pole stress)
A.4	190 km/h wind**	72.6%
B.1	CSA Heavy	104.2%
B.2	130 km/h wind	97.1%
B.3	1.2 cm ice thickness	99.9%
B.4	190 km/h wind**	166.9%
C.1	CSA Heavy	43.9%
C.2	200 km/h wind	101.3%
C.3	4 cm ice thickness	99.34%
C.4	190 km/h wind**	92.7%
D.1	CSA Heavy	14.0%
D.2	368 km/h wind	99.5% Note: guys fail at 178 km/h wind (23.79%)
D.3	9cm ice thickness	88.8% Note: guys fail at 3.3 cm (26.3% pole stress)
D.4	190 km/h wind**	27.82%

*CSA Heavy conditions simulate at a temperature -20℃, 0.4kPa wind speed and 1.25cm of ice thickness. Maximum allowable wind speed weather cases are run at a temperature of 0℃ and 0 cm ice thickness to determine the effect of only the wind. Maximum allowable ice thickness simulations were run at a temperature of -20℃ and 0.4kPa wind speed as wind would be typical in an ice storm.
**Wind levels are simulated as a 10 minute average wind speed as per CSA 22.3 No. 1:20.

4. Conclusion

As it can be seen in the table above, a storm hardening solution of a composite pole with storm guying (solution D) provides exceptional support against strong winds and heavy ice accumulation. The model was simulated to determine the maximum wind and ice thickness for the pole itself, as well as the maximum for typical storm guying (OAS0005) due to the fact that the guy wires appear to fail before the pole. Further investigation can be done into applying a stronger guying arrangement to use the full capability of the pole strength in a severe storm, however, it is clearly demonstrated that a composite pole is the superior pole type to use for storm hardening.

In addition to determining the maximum wind speed and ice loading for each storm hardening solution, the whole pole line was simulated with the derecho wind loading to demonstrate how the pole line will act in extremely strong winds that have occurred in the recent past. As it can be seen in the attached report summary, the intention of the storm support poles (L12, L17, L22, L27, L32 (removed from average above as an outlier), L37, L42 and L47 (removed from average above as an outlier)) is to remain intact to prevent a cascading pole failure effect, although the software does not have the capability of modelling cascading effects of pole failures as seen during the derecho. It should be noted that although the report shows several non-storm support poles failing, the model simulates the same wind pressure at each pole which would be unlikely in the real world, therefore, it can be assumed that the wind speed targets sections of the pole line and each pole failure can be isolated between storm support poles. It should also be noted that the wind pressure applied in SpidaCalc is simulated as an average 10 minute wind speed, not as a 3s wind gust, as per CSA 22.3 No 1:20. Therefore, the Derecho wind level case would be a much worse scenario than what was seen during the derecho as it is simulating 10 minutes of 190 km/h winds.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-37

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / p. 40 (pdf Exhibit 2 part 2, p. 40)

QUESTION(S):

a) Please explain the key drivers behind the increase in capital expenditures for System Renewal.
b) To what extent is the variance attributable to new technologies or specifications, higher unit costs for comparable work, or an increase in project volumes? Please provide a detailed breakdown.
c) In light of the good SAIFI/SAIDI figures, please explain why System Services costs are anticipated to nearly triple between the Historical/Bridge period and the test period.

RESPONSE(S):

a) As per Section 3.2 System Renewal of Schedule 2-5-1 - Distribution System Plan Overview, the increase in capital expenditures for System Renewal is predominantly driven by Station Equipment Renewals. Increased investment, guided by Predictive Analytics-driven risk assessments, focuses on renewing high-risk station assets, including decommissioning five high-risk 4kV substations and replacing critical station breakers. This addresses the deteriorating condition of infrastructure largely constructed between the 1960s and 1980s. The second major contributor is the strategic replacement of the current metering fleet with the Advanced Metering Infrastructure 2.0 (AMI 2.0), addressing its functional obsolescence. Increased replacement rates of Overhead and Underground assets due to their deteriorating condition and higher failure risk is the third largest driver.

b) Hydro Ottawa's System Renewal investments are attributable to a combination of new technologies/specifications, higher unit costs for comparable work, and an increase in project volumes to varying extents within the System Renewal program:

- **New Technologies or Specifications:**
  - Overhead (OH) Switch/Recloser Renewal: A portion of the increased investment is directly attributable to new technology. The program contemplates upgrading 40 manual OH switches to SCADAmates between 2026-2030, which are remote-controllable switches improving system observability and control.
  - UG Switchgear Renewal: Hydro Ottawa's proposed preferred alternative includes the ability to introduce remote operability to 10 UG switchgear units during renewal, to enhance system observability.
  - Resilience Investments: The pole renewal program includes incremental investments that enhance resilience, such as strategic undergrounding, line relocation, and fortification of critical overhead sections.
- **Higher Unit Costs for Comparable Work (Inflationary and Complexity Factors):**
  - Underground (UG) Cable Renewal: The UG cable renewal program experienced a significant increase in unit costs. The 2021-2025 unit rate of $0.3M/km was found to be too low, with actual costs averaging $0.7M/km (some reaching $1M/km) due to underestimating technical complexity and high inflationary costs for civil works. At the time of the 2021-2025 rate application submission, this unit rate would also not have taken into account the update to Hydro Ottawa's Underground Residential Transformer and Service Wire Sizes Guideline (USK0171), which governs the installation and upgrading of underground residential infrastructure to accommodate anticipated future electric vehicle loads; this factor alone underestimates the 2021-2025 unit rate by approximately 15%.
  - General Supply Chain Pressures: Please refer to Schedule 1-2-5 - Impacts on Inflationary Pressure for details on the impacts of inflationary and supply chain pressures due to shortages, tariffs, and other factors as a risk leading to equipment/material cost increases across all programs.

- **Increase in Project Volumes:**
  - Pole Renewal: The nearly $8M increase in the pole renewal program's spending from 2021-2025 to 2026-2030 (excluding resilience investments) is related to the increased volume of poles being proposed for replacement, aiming to keep pace with the extent of poles reaching their typical useful life (TUL) and degraded condition by 2030.
  - UG Switchgear Renewal: The forecasted spending increase is due to the increase in volume considered over the 2026-2030 period.
  - Vault Renewal: The forecasted spending increase is essential to manage the growing number of vault equipment owned by Hydro Ottawa that have reached their end of life
  - OH Switch/Recloser Renewal: The forecasted increase of $7.7M in spending is due to the increase in volume considered over the 2026-2030 period.

c) The primary driver for the increase in costs in System Service investments is to address capacity constraints in the distribution system to meet the growing needs of the service territory, through the Capacity Upgrades capital program. Although system reliability is a secondary driver for this program, these investments do not have a direct impact on SAIDI/ SAIFI. These investments will deliver tangible benefits to Hydro Ottawa's customers by supporting growing demand, facilitating renewable energy integration, enhanced grid observability and control, increased resilience to climate change and a more efficient and secure grid. For more details please refer to Schedule 2-5-8 - System Service Investments.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-38

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / p. 41 (pdf Exhibit 2 part 2, p. 41)

Preamble:
Hydro Ottawa states regarding the asset management process, that “By leveraging PA, Hydro Ottawa aims to make higher-value investment decisions, ultimately improving the management of its assets.”

QUESTION(S):

a) Are Hydro Ottawa's renewal investments solely or primarily intended to reduce risk?
   i) If no, please identify and discuss the other main drivers of renewal investments and for each renewal program or project for which risk reduction is not the primary goal, quantify the value created by addressing the other drivers.
   ii) If yes, how does Hydro Ottawa evaluate the cost effectiveness with which its proposed renewal investment programs and projects will mitigate risk costs?

b) Does Hydro Ottawa's enhanced Asset Management process enable it to quantify the efficiency of its proposed project and program spending in reducing risk costs?
   i) If yes, have the project and program capital expenditures proposed in this Distribution System Plan (DSP) been ranked on a dollar spent per risk dollar reduced basis?
   ii) If yes, please provide the list of all project and program spending proposed in this DSP ranked by dollar spent per risk dollar reduced.
   iii) If no, how does Hydro Ottawa know that the project and program spending proposed in this DSP will achieve the desired risk mitigation results?
   iv) If no, how soon will Hydro Ottawa's Asset Management process be capable of producing such a risk-reduction ranked project and program list?

RESPONSE(S):

a) Hydro Ottawa's renewal investments primarily aim to mitigate risks associated with aging and deteriorating assets, however other benefits, such as enhancing system efficiency and resilience are also considered.

i) Not Applicable.

ii) Please see the response to part c) of the response to interrogatory 2-Staff-59.

b) Hydro Ottawa's enhanced Asset Management process, which Hydro Ottawa infers to mean the implementation of Copperleaf PA (Ref 1), only informs System Renewal asset intervention strategies. It does not impact projects or programs across the entire Distribution System Plan With this added context, the implementation of Copperleaf PA enables Hydro Ottawa to evaluate the risk cost for each individual asset. Hydro Ottawa calculates the risk cost by leveraging the Intervention Value formula as described in part (c) of the response to interrogatory 2-Staff-59. The calculation of risk cost evaluation at the project and portfolio level are done within Copperleaf Portfolio (also described in 2-Staff-59 part (c)). Copperleaf Portfolio is not an enhancement to Hydro Ottawa's Asset Management as Hydro Ottawa has been leveraging this tool to calculate portfolio and project risk cost since 2014.

i) Hydro Ottawa does not rank program level capital expenditures against one another on a dollar spent per risk dollar reduced basis. At the project level, capital expenditures in this Distribution System Plan are ranked on a dollar spent per risk dollar reduced basis, however this ranking is done on an annual basis only (per Section 5.3.2 Project Level Investment Planning of Schedule 2-5-4 - Asset Management Process) and is therefore not available for investments within the 2026-2030 test period at this time.

ii) Please refer to the response provided in part (b)(i) above. A sample output of the project level ranking for 2025 is provided in part (a) of the response to interrogatory 2-SEC-42 (Attachment 2-SEC-42(A) - Copperleaf Key Outputs 2025).

iii) Hydro Ottawa measures its ability to achieve program level risk mitigation through the Performance Outcomes sections described in the 2-5-7 - System Renewal Investments and 2-5-8 - System Service Investments. See Section 5.4.2 of Schedule 2-5-4 - Asset Management Process. Hydro Ottawa does not evaluate the risk mitigation at the individual project level as the performance outcome is measured at the program level.

iv) Not applicable.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-39

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / p. 42 (pdf Exhibit 2 part 2, p. 42)

Preamble:
Hydro Ottawa states it has “significantly refined its testing, inspection, and maintenance programs […] For overhead assets, the reliance on age was substantially reduced due to improvements to the condition assessment framework for poles, alongside moderate improvements to condition data quality from Overhead (OH) switches and transformers through ground-based inspections.”

QUESTION(S):

a) How does Hydro Ottawa regularly test that the investments and results of the Asset Management pass Cost-Benefit analysis?
b) Since the change to condition-based assessments, what are the quantified benefits (i.e., extension of asset lives)?
    i) How are the benefits quantified and verified?

RESPONSE(S):

a) Hydro Ottawa ensures the cost-benefit of its asset management investments through a robust, multi-stage process. Initially, projects undergo a comprehensive scoring methodology that quantifies their value per dollar. This scoring considers the specific risks mitigated and the benefits realized from each investment, as per Section 5.3.2.1 in Schedule 2-5-4 - Asset Management Process. These scored projects are then fed into Copperleaf's portfolio optimization software. This tool strategically selects project candidates based on predefined

criteria, aiming to maximize overall value delivery within financial constraints. Crucially, Hydro Ottawa employs continuous monitoring of both the optimization results and the projects that proceed to completion. The performance data and outcomes from these completed projects are then fed back into the initial scoring of future projects and Copperleaf's optimization models. This iterative feedback loop allows Hydro Ottawa to continuously refine its understanding of cost-benefit, ensuring that future proposed projects are based on empirically validated data and consistently deliver optimal value.

b) An enhanced Asset Condition Assessment (ACA) framework, which incorporates additional condition parameters, provides a more accurate and comprehensive evaluation of asset health. It allows for more precise condition assessments to inform system renewal investment planning, ultimately improving the management of assets and focusing renewal investments on the assets with the highest need for intervention.

Some quantifiable benefits include:

- **Optimized Capital Allocation:** By focusing on assets in degraded condition and managing overall system risk, Hydro Ottawa can allocate capital more efficiently.
- **Reduced Risk of Catastrophic Failures:** By intervening on assets based on actual condition, Hydro Ottawa aims to reduce catastrophic failures which can result in significant repair costs, extensive outages, safety hazards, and environmental contamination (e.g., oil spills from transformers).
- **Improved Long-Term Financial Sustainability and Levelized Spending:** Condition-based assessment helps to avoid large spikes in asset renewal spending and the associated rate impacts on customers.
- **Increased Productivity and Cost Savings:** The pole renewal program, guided by condition, allows for the replacement of adjacent assets in poor condition including overhead switches, insulators, and overhead transformers. This synergy drives cost savings and efficiencies by consolidating work, rather than addressing issues in isolation as they arise.

Benefits from condition-based assessments are quantified and verified through three methods:

- **Copperleaf Predictive Analytics (PA):** PA calculates intervention value and specific risk measures (reliability, safety, environmental, compliance, financial) by leveraging asset health index and failure probability. This allows Hydro Ottawa to prioritize System Renewal investments based on risk mitigation. (See Section 5.1.4: Asset Risk Assessment under Schedule 2-5-4: Asset Management Process.)
- **ISO 55001 Certification:** Hydro Ottawa's asset management process, including condition assessments, is ISO 55001 certified and undergoes regular internal and external audits, providing external verification of its effectiveness. (See Section 4.4.5: ISO 55001 - Asset Management System Recertification under Schedule 2-5-4: Asset Management Process.)
- **Continuous Data Tracking:** Ongoing collection of asset failure information (age, condition at failure) refines failure curves and validates predictive analytics, verifying the long-term benefits of condition-based assessments.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-40

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / p. 44 (pdf Exhibit 2 part 2, p. 44)

Preamble:
Hydro Ottawa states, regarding the Grid Modernization Strategy Roadmap Creation, “This initiative prioritized enhancing grid reliability, flexibility, resilience, and sustainability through a methodical, two-phased approach. The first phase began with establishing a baseline maturity level by completing an assessment of Hydro Ottawa's existing grid infrastructure and operational capabilities. This evaluation was then compared against a desired future state vision across various time horizons, which revealed key areas for improvement.”

QUESTION(S):

a) Is Hydro Ottawa's position that its current reliability meets customer expectations?
b) Are Hydro Ottawa's customers demanding improved reliability performance? Please discuss.
    i) If yes, please demonstrate that Hydro Ottawa's planned improvements will address the reliability concerns being raised by customers. For example, if customers are concerned about the long duration outages associated with extreme events such as the 2022 Derecho, show how Hydro Ottawa's planned grid enhancements would directly mitigate the duration of outages caused by such events.
c) How is the desired future state assessed and validated? What assurances are in place to ensure that the proposed build-out is driven by need rather than preference (i.e. customer projections may reflect upper-bound requirements)?

RESPONSE(S):

a) Hydro Ottawa has consistently delivered strong reliability performance, positioning it as a top-performing utility in the province. As noted in the company's 2024 Annual Report, customers had power for an average of 99.98% of the time. This builds upon a strong performance in 2023, which represented the company's second-best result for outage frequency on record (see page 20 of Attachment 1-5-2(A) - 2023 Hydro Ottawa Holding Inc. Annual Report).

Further, customer surveys independently affirm Hydro Ottawa's positive reliability performance. Of note, in Attachment 1-4-1(C) - 2024 Customer Satisfaction Survey - Residential & Small Comm, page 24, the Utility PULSE Report Card awarded Hydro Ottawa an "A" grade for power quality and reliability. Hydro Ottawa's customer engagement results further demonstrate a higher level of satisfaction with reliability compared to both Ontario and National averages. This performance is reflected across multiple key indicators: 89% of respondents reported satisfaction with 'providing consistent, reliable energy', 87% agreed that Hydro Ottawa has a standard of reliability that meets expectations, and 85% stated that Hydro Ottawa quickly handles outages and restores power. Please refer to Attachment 1-4-1(C) - 2024 Customer Satisfaction Survey, page10; and Schedule 1-4-1 - Customer Engagement Ongoing, page 5, Table 3.

Even with a strong history of performance, results from Hydro Ottawa's customer engagement activities on this rate application, which can be found in Attachment 1-4-2(A) - Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application, confirm that customers are demonstrating a clear and consistent demand for improved reliability performance, particularly in light of evolving challenges like extreme weather and the energy transition.

b) Hydro Ottawa's proposed investments in reliability are directly informed by and responsive to extensive customer feedback. Results from Hydro Ottawa's customer engagement activities on this rate application demonstrate that customers view improved reliability as their highest priority (Attachment 1-4-2(A) - Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application, page 27/500 - Key Findings).

Furthermore, customers have expressed a direct demand for specific investments aimed at

enhancing resilience against the increasing frequency of severe weather events. Feedback consistently called for Hydro Ottawa to invest in "hardening the system," "modernizing the grid," and "burying wires underground" (Attachment 1-4-2(A) - Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application, pages 35, 76, 105). Verbatim comments directly reference the impacts of events like the May 2022 derecho and winter storms, linking these experiences to a desire for system improvements (Attachment 1-4-2(A) - Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application, pages 65, 96).

Finally, Hydro Ottawa's engagement identified that experiences with "unreliability" and "extended outages" were a more significant driver of dissatisfaction for suburban customers than for their downtown counterparts, underscoring the need for targeted reliability improvements in these specific areas (Attachment 1-4-2(A) - Customer Engagement Report on Hydro Ottawa's 2026-2030 Rate Application, page 34).

To meet the evolving needs of customers, Hydro Ottawa must make prudent investments in its system. This plan is designed to address the vulnerabilities of aging infrastructure while proactively preparing for more frequent and severe weather events and emerging cybersecurity threats. These investments are all the more critical as the community's reliance on electricity grows with electrification, where a dependable power supply is no longer just a convenience but a necessity.

i) Hydro Ottawa's planned grid enhancements related to reliability are summarized in Section 3 of Schedule 2-5-8 - System Service Investments. These programs are targeted at addressing the customer reliability concerns highlighted in part (b) above. Hydro Ottawa assessed three alternatives to test how different combinations of programs for Hydro Ottawa's planned grid enhancements would directly mitigate customer concerns. A balanced approach was selected as the preferred alternative due to its strategic combination of existing programs with targeted investments in resilience and grid modernization. This approach achieves a balance between enhancing grid reliability and observability while maintaining cost-effectiveness. More details are available in Section 3.6 of Schedule 2-5-8 System Service Investments.

c) To ensure that the proposed system build-out is based on demonstrated needs rather than customer preferences, as described in Section 3.1 of Schedule 2-5-4 - Asset Management Process, Hydro Ottawa's capital expenditure plan is an output of the utility's integrated business planning process. Through this process, Hydro Ottawa advances its overall strategic objectives and provides value to customers by establishing goals and priorities, allocating resources, monitoring performance, identifying areas for improvement, and adapting to developments in the external business environment. The critical component in ensuring the capital expenditure plan is grounded in demonstrated need is the role of the business strategies in guiding the objectives of the expenditure plan. Five business strategies oversee the key asset categories: Asset Management, Grid Modernization, Digital, Facilities, and Fleet. These strategies are grounded in a consistent framework that aligns corporate Strategic Direction and customer feedback with individual asset needs. Refer to section 3.4 of Schedule 2-5-4 - Asset Management Process for details on each strategy and their objectives.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-41

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / pp. 47-48 (pdf Exhibit 2 part 2, pp. 47-48)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 3 / p. 40 (pdf Exhibit 2 part 2, p. 202)

Preamble:
In reference 1 Hydro Ottawa states “Despite the increased risk scores associated with severe wind events, the overall risk level for the majority of Hydro Ottawa's infrastructure remains unchanged […] the primary areas of vulnerability within Hydro Ottawa's system, namely overhead assets, remain consistent with previous assessments.” Additionally, Hydro Ottawa highlights “the increasing frequency of severe weather events and the community’s dependence on reliable service.”

Reference 2 contains Figure 8 – Major Event Day Threshold, which provides data from 2019-2023.

QUESTION(S):

a) What is the probability that Hydro Ottawa will experience another wind storm event similar to the 2022 Derecho within the next 20 years? Please show how the probability was calculated.
b) Please provide the data underlying the claim that the frequency of severe weather events is materially increasing. Please provide results for a 40-year historical period, showing total percentage of customers interrupted due to each event, and cumulatively in each year of the 40-year historical period.
c) Please provide Hydro Ottawa's definition of severe weather events and explain if the definition of "severe weather events" is the same as or different from the definition Hydro Ottawa uses for events responsible for triggering "Major Event Days".

RESPONSE(S):

a) The probability over the next 20 years is not available. Annual probabilities, calculated by Stantec Consultants, were calculated for the baseline period (1981-2010) and the 2050's (2041-2070) for each climate parameter. The annual probabilities were then translated to the study period probabilities by estimating the likelihood of occurrence over a 30-year period (refer to Appendix C Forensic Analysis Derecho Event May 21, 2022, Section 2.1.4, of Attachment 2-5-4(B) - Addendum Report to Distribution System Climate Vulnerability Risk Assessment and Climate Change Adaptation Plan).

During the 2022 Derecho, wind speeds measured at the Ottawa International Airport were 120 km/hr; however, damage assessment indicated speeds were consistent with the 180-195 km/hr range (refer aforementioned Appendix C - Forensic Analysis Derecho Event May 21, 2022).

The 2023 Addendum Report to Distribution System Climate Vulnerability Risk Assessment and Climate Change Adaptation Plan (Attachment 2-5-4(B)), produced by Stantec Consulting for Hydro Ottawa, further reports the annual probability of high wind speeds above 130 km/hr as 2.90% and for 180 km/hr as 1.25% (refer to Table 3: Changes in Climate Parameter Probabilities and Additional Wind Threshold Probabilities of Attachment 2-5-4(B)).

Stantec Consulting's methodology for these probabilities is outlined in Section 2.1 of their report.

b) Please see Excel Attachment 2-Staff-41(A) - DX System Climate Risk Vulnerability Assessment_20200605 for the data supporting the claim that the frequency of severe weather events is increasing materially. In particular refer to Table 5 Summary of Potential Climatic Changes by Mid-Century in the Greater Ottawa Region.

Additionally, the Ministry of Energy's *Vulnerability Assessment for Ontario's Electricity Distribution Section* Report highlights that climate change is not a distinct concern but a

present and growing challenge for electricity distributors, with measurable impacts already evident in the province:

> *Climate change is an important risk factor for the electricity sector: warmer temperatures will change the size and timing of demand peaks while increasingly frequent extreme weather events pose risks for critical infrastructure. The impacts of climate change are already being experienced in Ontario. For example, observed annual average temperatures in 2004 – 2013 were 1.0°C higher than 20 years prior (1984 – 1993). In addition, all of the top ten hottest years in global recorded history occurred within that timeframe. With these increases in average temperatures come increases in the frequency and intensity of extreme weather such as thunderstorms, extreme precipitation and extreme heat, and an increase in conditions that catalyze drought, wildfires, and thunderstorms.10,11 Weather-related risks are already one of the primary causes of electrical outages, and a changing climate brings with it significant additional pressure over the coming decades.At the same time, climate change may increase the importance of reliable electricity as a result of policies driving widespread and multisectoral electrification and extreme temperatures increasing the importance of climate control technology such as air conditioning.*[1]

c) Severe weather events, although not explicitly defined, are understood to be conditions that significantly disrupt the electricity distribution system, exceeding normal manageability. These events include customer interruptions caused by rain, ice storms, snow, high winds (approximately 90 km/hr or higher), extreme ambient temperatures, freezing fog, or frost. They are characterized by stressing Hydro Ottawa's system beyond its design standards and capabilities. A subset of these events is classified as “Major Event Days” as per the OEB’s definition.

[1] Ministry of Energy, *Vulnerability Assessment for Ontario’s Electricity Distribution Sector - Report on Anticipated Climate Change Impacts and Considerations for Adaptation and Resilience*, pages 9-10: https://www.ontario.ca/files/2024-05/energy-vulnerability-assessment-for-ontarios-electricity-distribution-sector-en-2023-05-23.pdf

In May 2016, the Ontario Energy Board introduced Major Event reporting requirements and defined a major event. Data is only available from 2016 onward. Table A below provides a summary of the percentage of total customers interrupted as a result of MEDs since 2016. For additional details, refer to Schedule 2-5-3 - Performance Measurement for Continuous Improvement, Table 22 - 2019-2023 Major Event Day Overview.

Table A - Total Percentage of Customers Interrupted for Each Major Event

Date	% Customers Interrupted
2016-07-01	4%
2017-01-04	6%
2017-09-27	3%
2018-04-16	17%
2018-05-04	19%
2018-09-21	65%
2019-04-15	13%
2019-07-05	21%
2019-11-01	4%
2020-03-07	3%
2020-10-18	3%
2021-06-14	5%
2022-05-21	54%
2022-06-18	8%
2022-12-23	19%
2023-04-05	45%
2023-06-26	4%
2023-07-28	10%

Distribution System Climate Risk and Vulnerability Assessment

Final Report

November 11, 2019

Prepared for:

Hydro Ottawa Limited
2711 Hunt Club Road
Ottawa, ON K1G 5Z9

Prepared by:

Stantec Consulting Ltd.
400-1331 Clyde Avenue
Ottawa, ON K2C 3G4

Project No. 122170294

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Prepared by _____
(signature)

Riley Morris, P.Eng.

Guy Felio
Digitally signed by Guy Felio
Date: 2019.11.15 08:47:34 -05'00'

Reviewed by _____
(signature)

Guy Felio, P.Eng.

Nicole Flanagan
Digitally signed by Nicole Flanagan
Date: 2019.11.12 12:10:19 -05'00'

Approved by _____
(signature)

Nicole Flanagan, P.Eng.

RM/FG/NF/cf

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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.



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.

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.

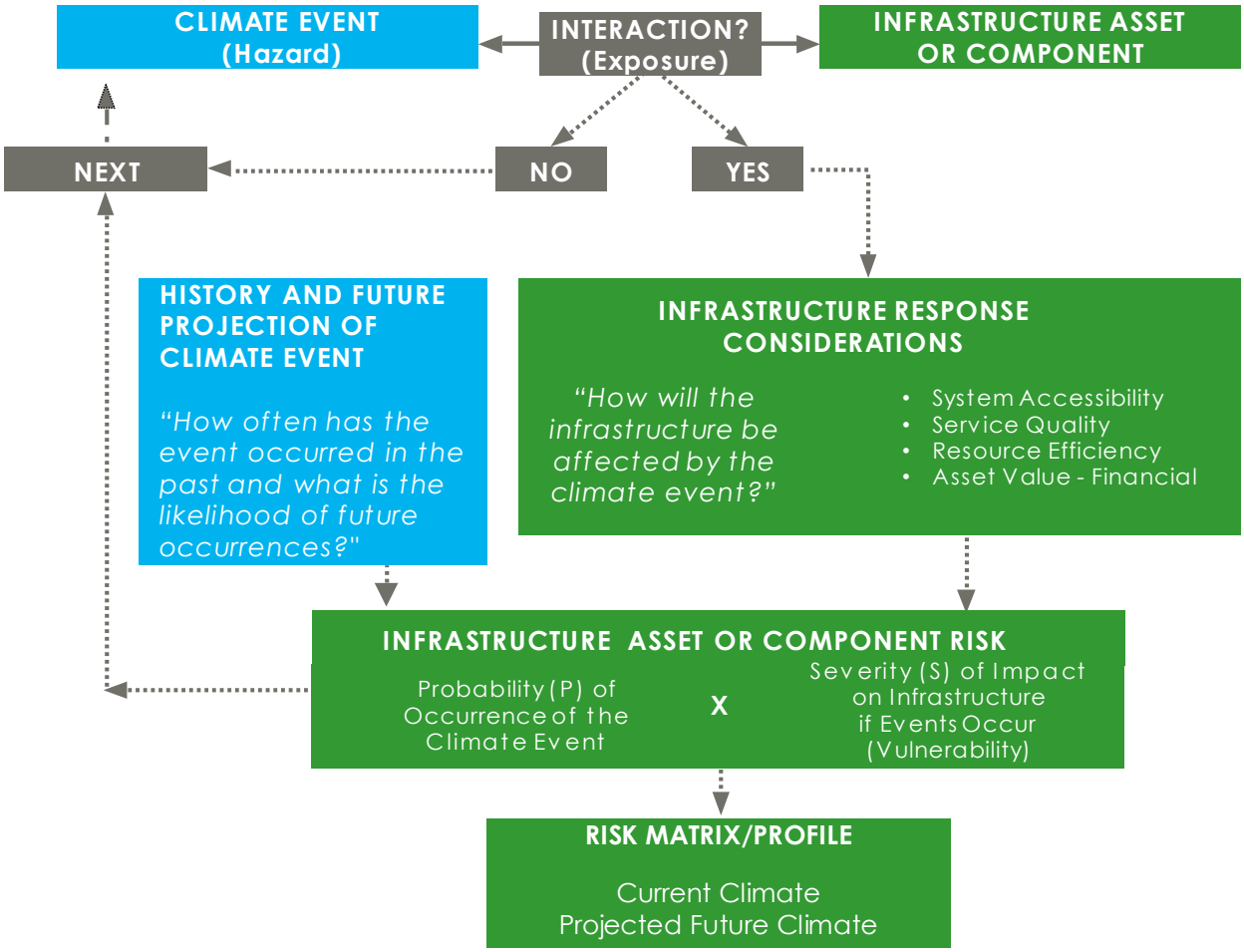
Climate Parameter	Projected Climatic Changes by Mid-Century
Temperature – Extreme Heat	• Increased frequency and intensity • Increased frequency and length of heat waves
Temperature – Extreme Cold	• Decreased frequency and intensity • Occurrence of extreme cold outbreaks (“Polar Vortex” winters) likely to continue
Rain (Short Intensity – High Duration)	• 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	• Increased frequency • Increased winter season (e.g. January) events
Snow	• Likely decrease in annual total accumulation • Continued occurrence and steady frequency of larger individual events



Climate Parameter	Projected Climatic Changes by Mid-Century
High Winds	• Slight increase in frequency of high wind events (e.g. 90 km/hr; 120 km/hr)
Lightning	• Increased frequency (by about 12% per degree Celsius of warming) • Increased length of the higher frequency lightning season
Tornadoes	• 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	• Likely increase
Frost (Freeze-Thaw Cycles)	• 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.





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.

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.

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



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.

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- Preparation of a climate risk and vulnerability assessment report.

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.

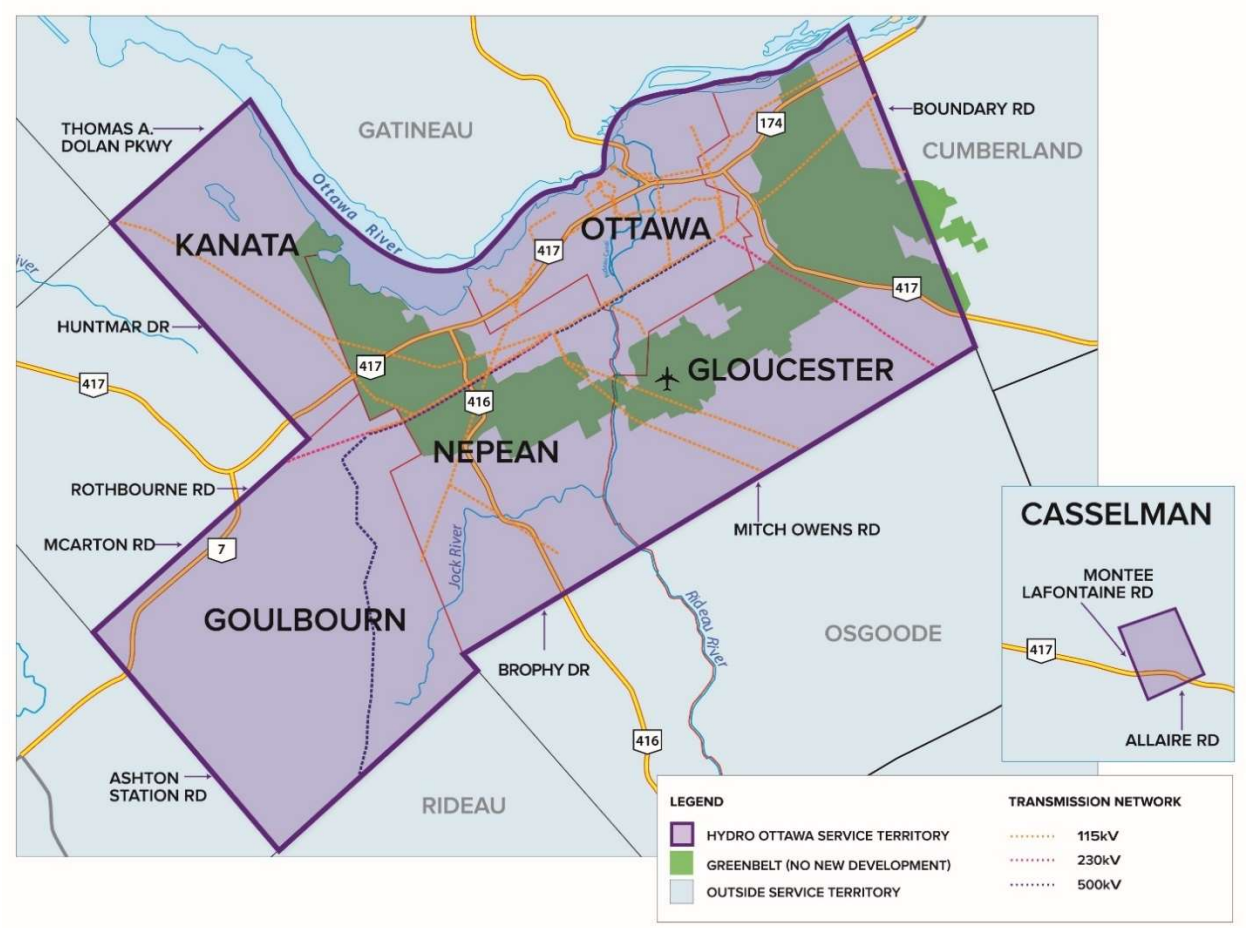


Figure 1 Map of Hydro Ottawa Service Territory[1]

[1] Hydro Ottawa. 2018. <https://hydroottawa.com/about/governance/overview>

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.**

Methodology
November 11, 2019

			Impact				
Risks / Opportunities	Health, Safety & Environment	Safety	Should the main risk or opportunity be classified as a Safety risk, PRO-MS-001.04 shall be evaluated through notifying the Manager, Occupational and Public Safety				
	Health, Safety & Environment	Environment	Should the main risk or opportunity be classified as an Environmental risk, PRO-MS-001.04 shall be evaluated through notifying the Manager, Environment and OHSE Management System				
	Compliance	Compliance	N/A	Noncompliant with corporate regulation/policy	Noncompliant with municipal regulation	N/A	Noncompliant with federal/provincial regulation
	Levels of Service	System Accessibility	N/A	N/A	Load demand is exceeding planning limits	Load demand is exceeding thermal limits	Unable to service new load
	Levels of Service		N/A	N/A	Generation is exceeding planning limits	Generation is exceeding thermal limits	Unable to service new ERFs
	Levels of Service	Service Quality	Service interruption resulting in <10,000 customer minutes interrupted	Service interruption resulting in >10,000 customer minutes interrupted	Service interruption resulting in >500,000 customer minutes interrupted	Service interruption resulting in >3,000,000 customer minutes interrupted	Service interruption resulting in >10,000,000 customer minutes interrupted
	Levels of Service		Service quality resulting in customer complaint, but meets CSA standards	Service quality resulting in customer escalation, but meets CSA standards	N/A	N/A	Service quality resulting in not meeting CSA standards
	Resource Efficiency	Resource	Requires <10 hours of overtime to complete O&M work or undergo training	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 >1,500 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
	Resource Efficiency		Requires <100 hours of overtime to complete capital work	Requires >100 hours of overtime to complete capital work	Requires >2,500 hours of overtime to complete capital work	Requires >15,000 hours of overtime to complete capital work	
	Asset Value	Financial	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 >$300k	Financial risk resulting in an O&M expense of >$1M
	Asset Value		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 >$3M	Financial risk resulting in a capital expense of >$10M
	Corporate Citizenship	Corporate Brand	N/A	Negative publication on social media (remains local)	Negative publications at a municipality level	Negative publications at a provincial level	Negative publications at a national level
	Corporate Citizenship		N/A	Negative customer satisfaction survey results, while above comparators	Negative customer satisfaction survey results, while below comparators	N/A	N/A
			1	4	9	16	25
	Probability		Insignificant	Minor	Moderate	Extensive	Significant
Likelihood	(May occur only in exceptional circumstances)	1	Rare	0	0	0	0	0
	>5% (Could occur)	2	Unlikely	2	8	18	32	50
	>35% (Might occur)	3	Possible	3	12	27	48	75
	>65% (Will probably occur)	4	Likely	4	16	36	64	100
	>95% (Is expected to occur)	5	Almost Certain	5	20	45	80	125

Figure 2 Hydro Ottawa Asset Management Risk Procedure Matrix

2026-2030 Custom IR
EB-2024-0115
Interrogatory Response
2-Staff-41
Attachment A
ORIGINAL
Page 16 of 162

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.

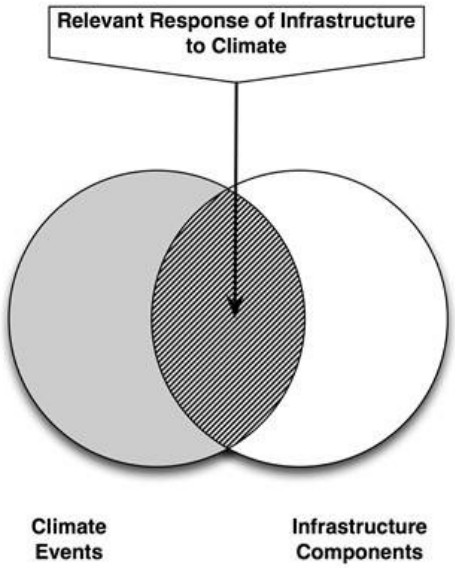


Figure 3 Diagram representing the interaction between climate events and infrastructure components

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.

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.

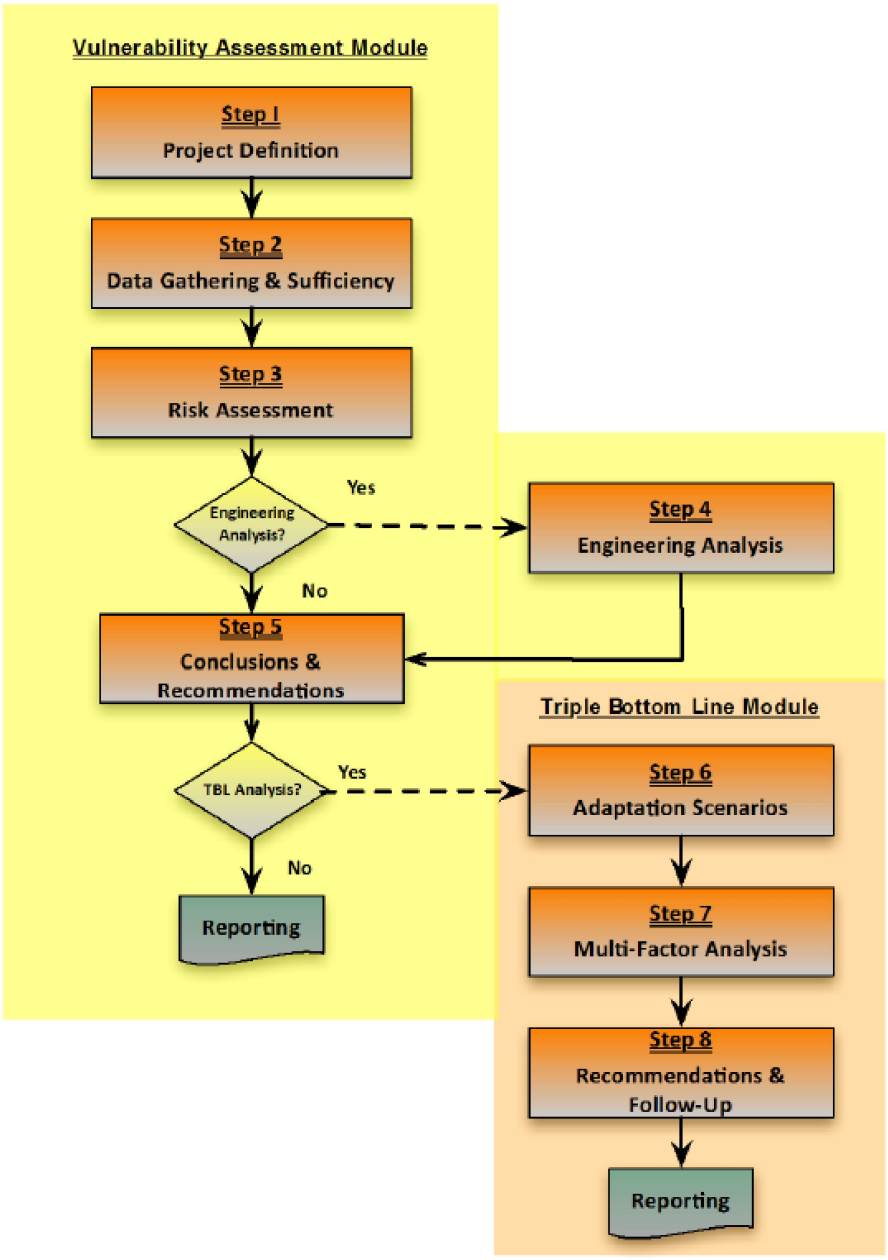


Figure 4 Flow Chart Illustrating the PIEVC Protocol Process

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.

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.

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:

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

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)	

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.

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).

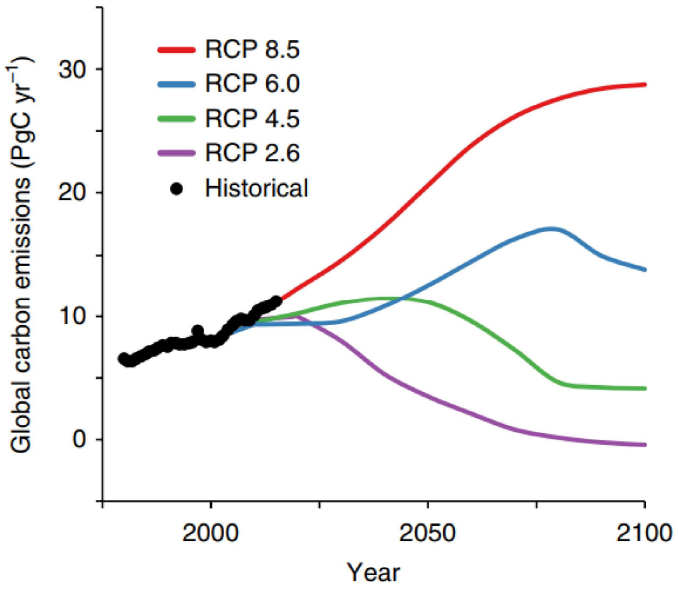


Figure 5 Historical CO_2 emissions for 1980-2017 and projected emissions trajectories until 2100 for the four Representative Concentration Pathway (RCP) scenarios. Current global emission trends have very closely followed the "business-as-usual" RCP8.5 scenario trajectory. Figure from Smith and Myers, 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**.

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.

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.

Table 4 List of Climate Parameters Considered in this Study

Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Temperature			
Extreme Heat	$T_{max} \geq 30°C$	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	Tmax ≥ 30°C identified as a personnel issue (associated with physical exertion and risk of heat exhaustion); Tmax of 40°C used as a design value; Higher temperature thresholds lead to extra loading on the system from increased commercial and residential air conditioner use; Thermal stress can result in cracking and fissuring in materials (e.g. polymer-based materials).
	$T_{max} \geq 35°C$		
	$T_{max} \geq 40°C$	Asset Value – High temperature operating threshold	
	$T_{mean} \geq 30°C$	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 $T_{max} \geq 30°C$ and $T_{min} \geq 23°C$	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	System overloading common after 3 days of consecutive heat due to high demands on electrical grid (e.g. transformers) by increased air conditioning use; Equipment unable to cool properly reducing functionality.
	Consecutive Days with $T_{max} \geq 30°C$ and $T_{min} \geq 25°C$		
Extreme Cold	$T_{min} \leq -35°C$	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	Identified as a personnel issue; Older sections of Ottawa may experience overcapacity due to extensive use of electric baseboard heating; Tmin of -40°C used as a design value; Extreme cold can result in underperformance of vehicles and outdoor infrastructure.
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	Design threshold; 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); Extreme rain can result in reduced accessibility to assets (e.g. flooded roadways).

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	

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) EF1+ point probability (i.e. tornado striking a specific asset, e.g. a substation, in the City of Ottawa service area)	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).
Invasive Species			
Emerald Ash Borer (EAB)	$T_{min} \leq -30°C$	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; Tmin ≤ -30°C is the kill threshold for EAB mature, non-feeding larvae.
Giant Hogweed	3 Days $T_{max} \leq -8°C$	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 Tmax ≤ -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.



Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Frost			
Freeze-thaw Cycles	Daily T_{max} T_{min} temperature fluctuation around 0°C	Asset Value – Freeze-thaw cycles can result in weathering and damage to hard infrastructure (minimum of 30 cycles/year required to damage concrete) Level of Service – Freeze-thaw cycles can lead to icy conditions which become a health and safety concern	Hydro Ottawa personnel have noted more mid-winter events, resulting in more pole fires; Freezing moisture known to cause failure in underground cabling, has increased incidents of pole fires, and limits access by crews; Associated thermal stresses and frost weathering can result in cracking and fissuring in materials (e.g. polymer-based materials); Large temperature ranges in freeze-thaw cycles can result in increased weathering and damage.

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).

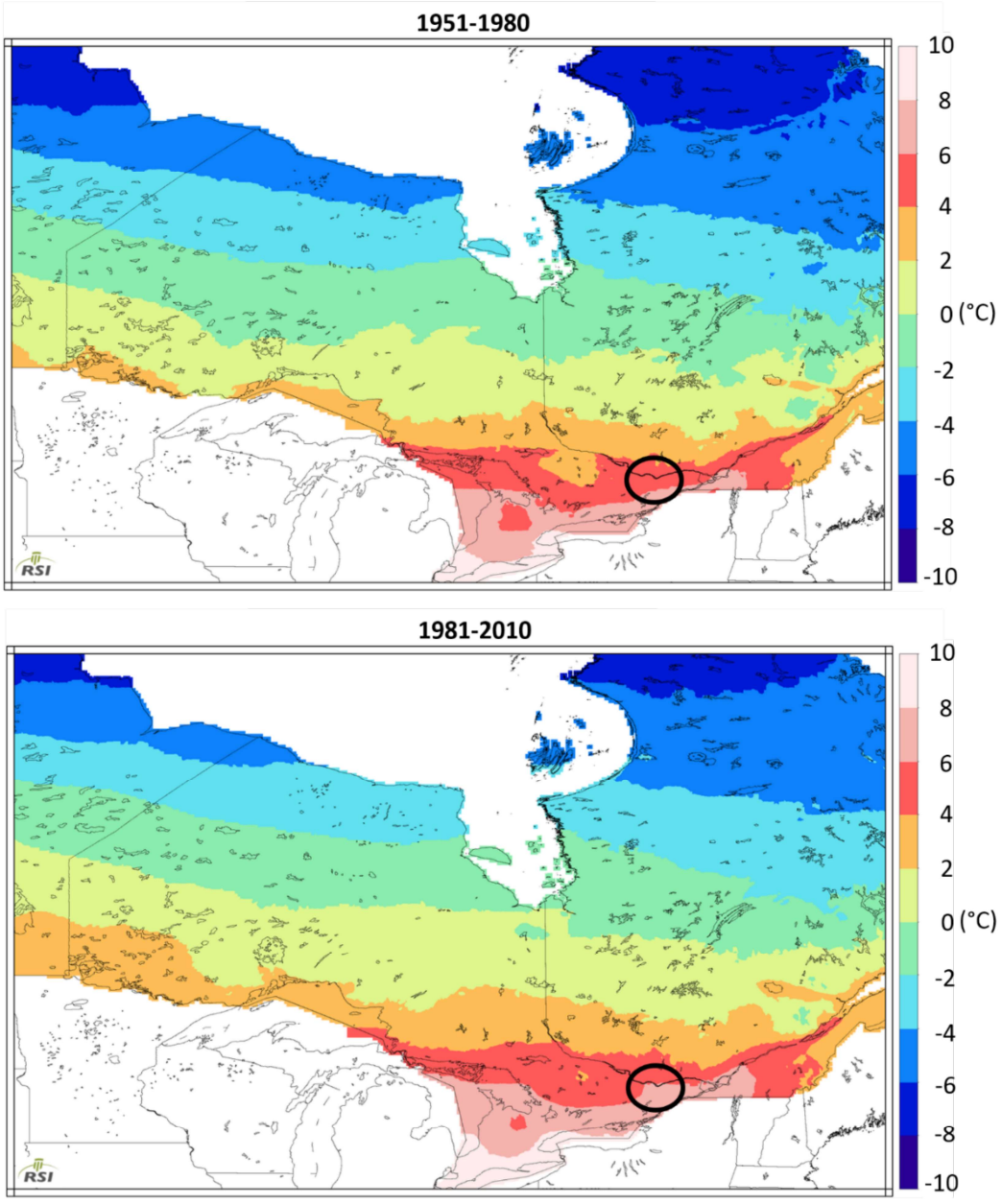


Figure 6 Observed annual mean (2m) air temperature over the 1951-1980 (upper) and1981-2010 (lower) periods. The change in mean annual temperature can be inferred from comparison of the plots (i.e. the difference in the colouration), with observed increases in temperature throughout Southern Ontario. 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.)

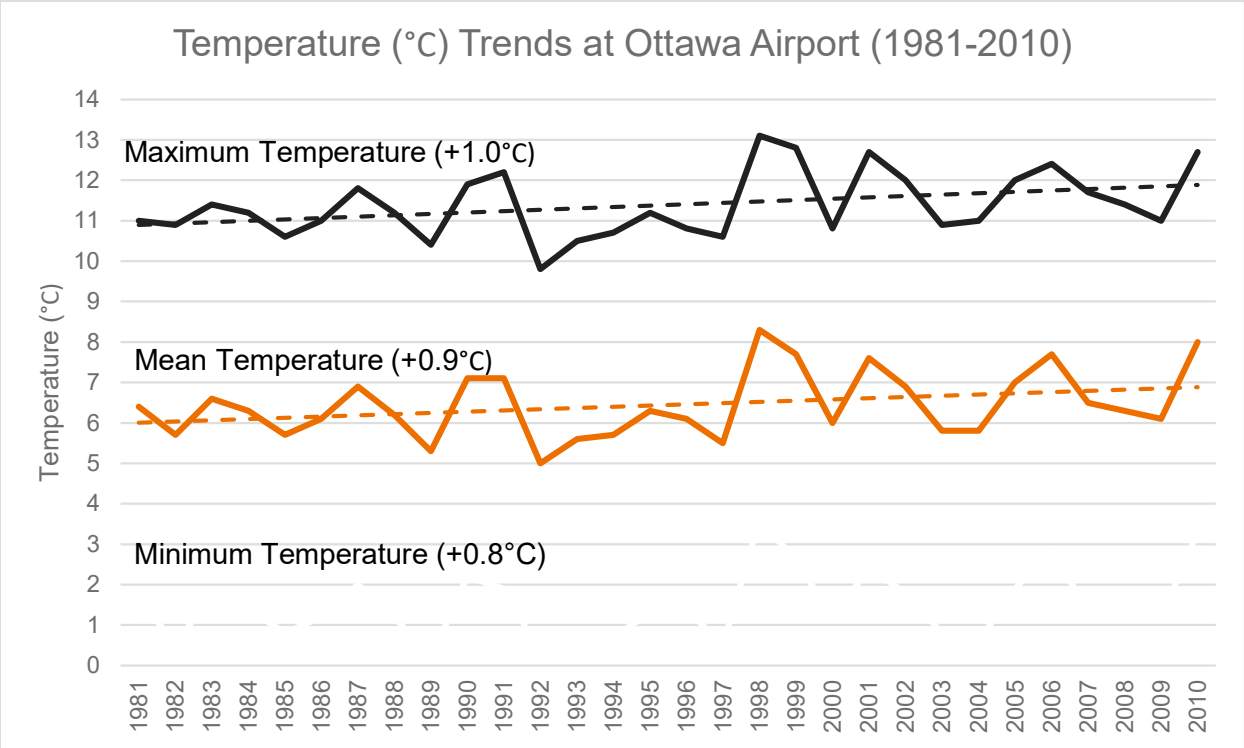


Figure 7 1981-2010 Annual Mean, Maximum, and Minimum Temperature Data and Trends at Ottawa Airport

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.

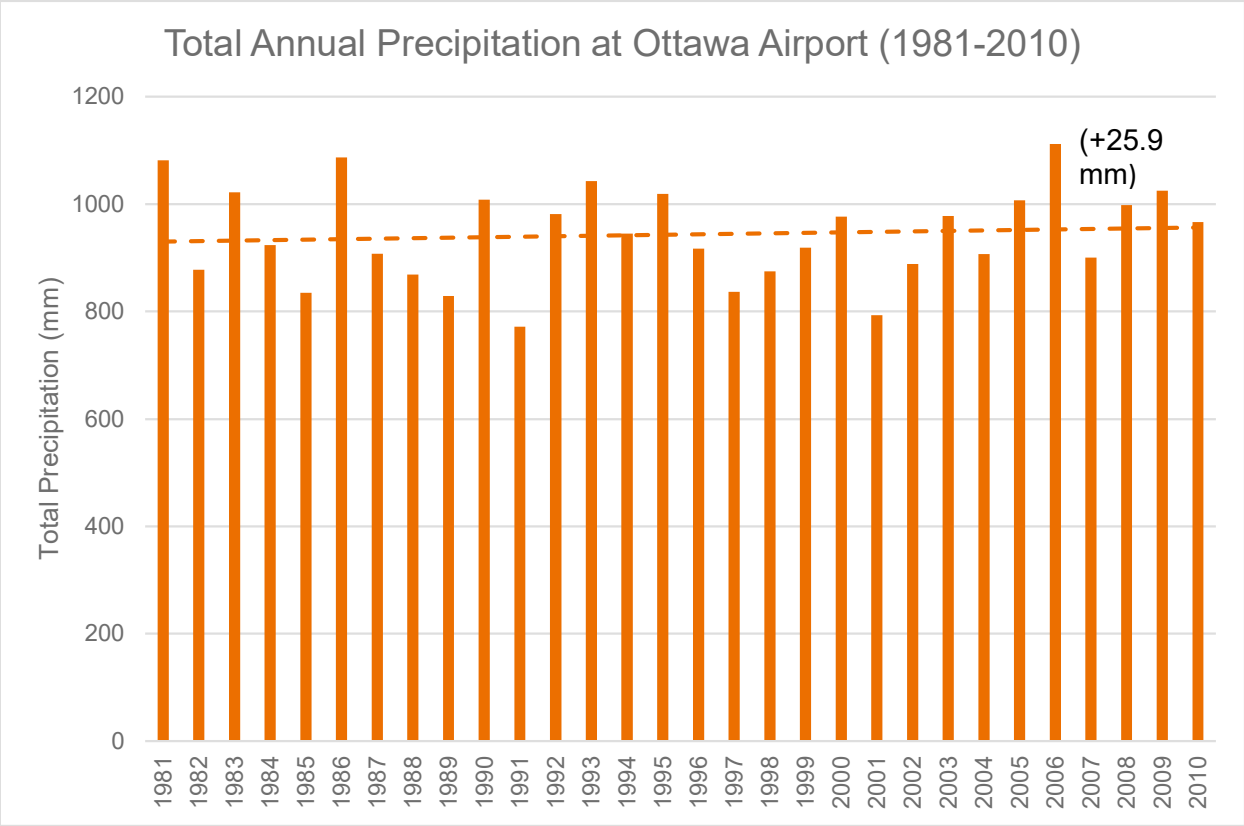


Figure 8 1981-2010 Total Annual Precipitation Data and Trend at Ottawa Airport

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).

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.

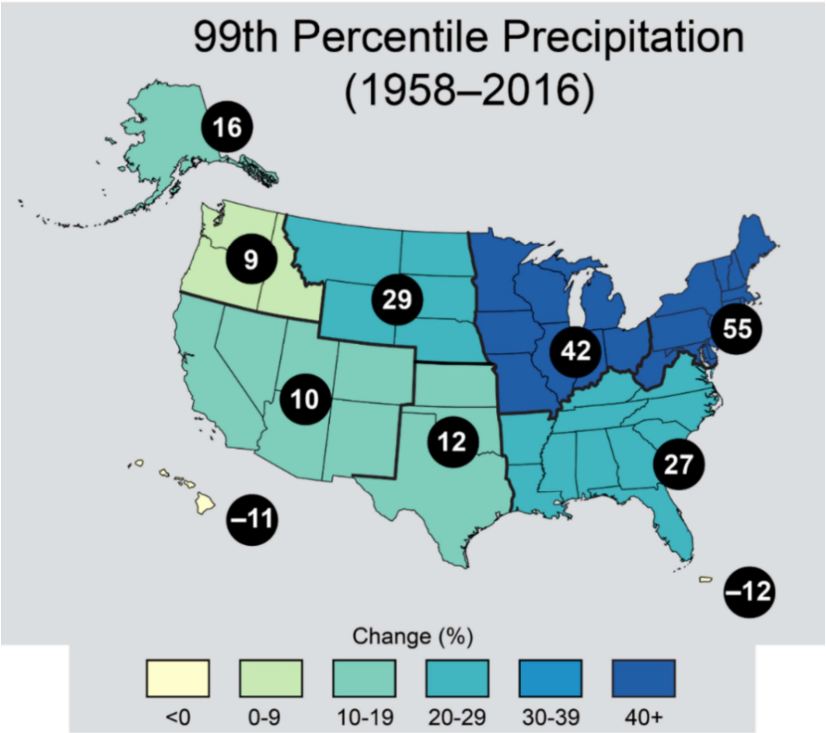


Figure 9 Percent increases in the amount of precipitation falling in daily events that exceed the 99th percentile of all days with precipitation (i.e. the total precipitation falling in the top [heaviest] 1% of daily precipitation events) in the United States, 1958-2012, calculated from daily precipitation 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,

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	• Increased frequency and intensity • Increased frequency and length of heat waves
Temperature – Extreme Cold	• Decreased frequency and intensity • Occurrence of extreme cold outbreaks ("Polar Vortex" winters) likely to continue
Rain (Short Intensity – High Duration)	• 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	• Increased frequency • Increased winter season (e.g. January) events
Snow	• Likely decrease in annual total accumulation • Continued occurrence and steady frequency of larger individual events
High Winds	• Slight increase in frequency of high wind events (e.g. 90 km/hr; 120 km/hr)
Lightning	• Increased frequency (by about 12% per degree Celsius of warming) • Increased length of the higher frequency lightning season
Tornadoes	• 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	• Likely increase
Frost (Freeze-Thaw Cycles)	• Decrease in annual total number of freeze-thaw days • Increase in monthly totals in the shoulder seasons (e.g. November and March)

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.



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) *Revised-October, 2011	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.

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 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.

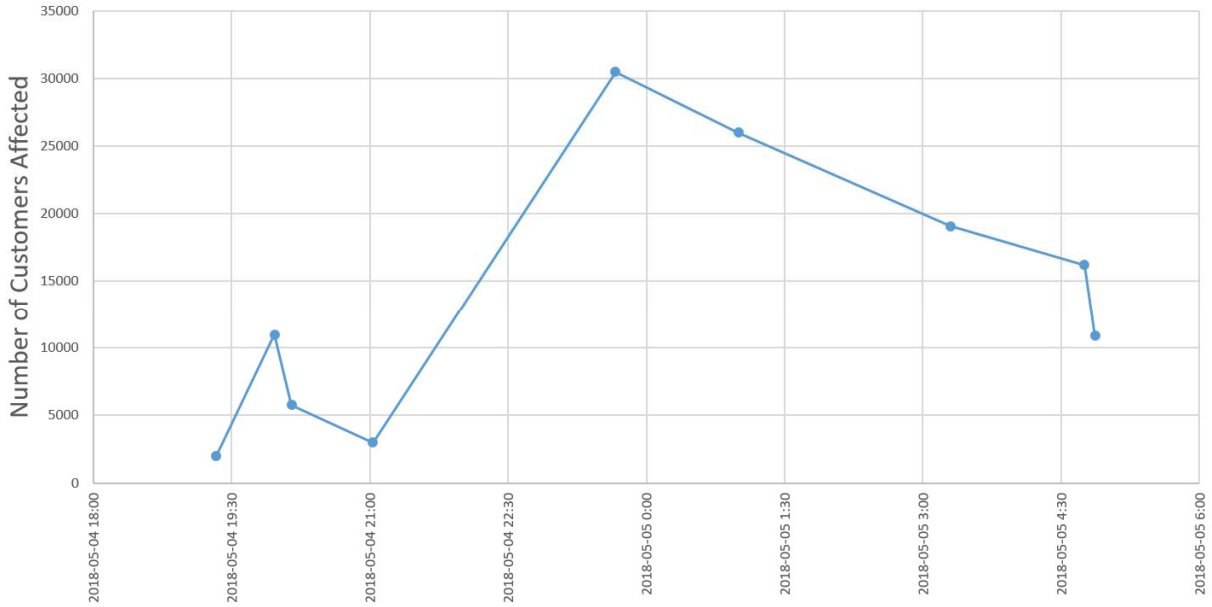


Figure 11 Timeline describing number of customers affected during May 4, 2018 windstorm. Note small peak of ~11,000 between 7:30 and 8:00 PM EDT, followed by much larger peak of >30,000 later in the evening. Total number of customers affected based on outages reported by Hydro Ottawa's Twitter account.

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.

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).

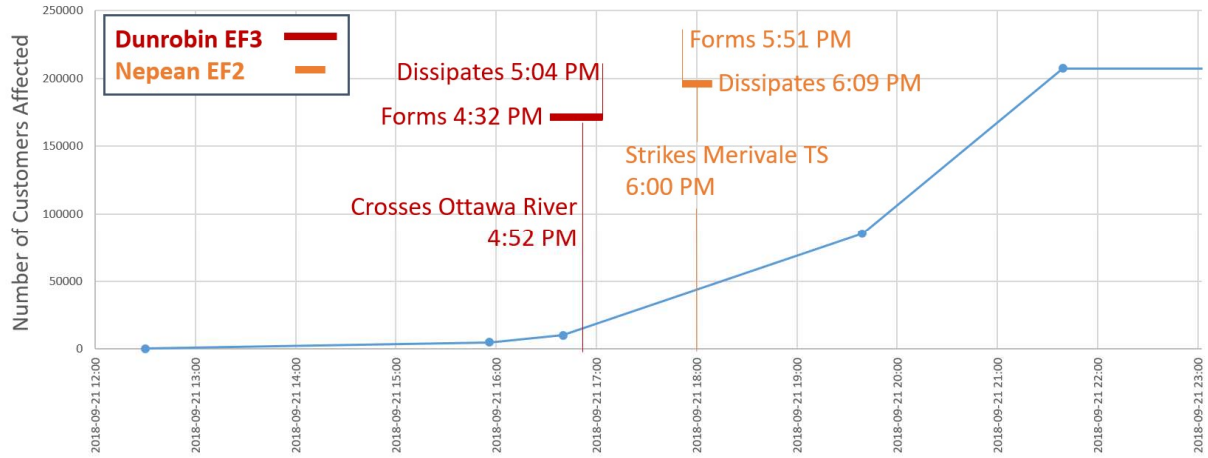


Figure 12 Timeline comparing the total number of reported customers affected versus the occurrence of the Kinburn-Dunrobin-Gatineau tornado (red) and the Nepean-South Ottawa tornado (orange). Outage totals are based on those reported by Hydro Ottawa's Twitter account and the final total based on post-event 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.

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.

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.

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.

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.

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**.

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	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
Temperature – Extreme Heat										
Daily maximum temp. of 30°C and higher	100% (~14-15 yr^{-1})	5	100%	5	100% (~42 yr^{-1})	5	100%	5	No change	No change
Daily maximum temp. of 35°C and higher	50% (< 1 yr^{-1})	3	>99%	5	100% (~6 yr^{-1})	5	100%	5	+ 2	No change
Daily maximum temp. of 40°C and higher	6% (< 1 yr^{-1})	2	84%	4	100% (~1-2 yr^{-1})	5	100%	5	+ 3	+ 1
Daily average temp. of 30°C and higher	3% (< 1 yr^{-1})	1	60%	3	100% (~1-2 yr^{-1})	5	100%	5	+ 4	+2
Heat wave: Consecutive days with $T_{max} \geq 30°C$ and $T_{min} \geq 23°C$	7% (< 1 yr^{-1})	2	89%	4	100% (~2 yr^{-1})	5	100%	5	+ 3	+ 1
Heat wave: Consecutive days with $T_{max} \geq 30°C$ and $T_{min} \geq 25°C$	0% (0 yr^{-1})	1	0%	1	37% (<1 yr^{-1})	3	>99%	5	+ 2	+ 4
Temperature – Extreme Cold										
Daily minimum temp. of -35°C and colder	3% (< 1 yr^{-1})	1	60%	3	0.1% (Rare)	1	3%	1	No change	- 2
Rain										
50 mm of rainfall in 1 hour	1% (< 1 yr^{-1})	1	~25%	2	4.5% (< 1 yr^{-1})	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

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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
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 [gemination requirement])	100% (25 yr^{-1})	5	100%	5	100% (17 yr^{-1})	5	100%	5	No change	No change

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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
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

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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.

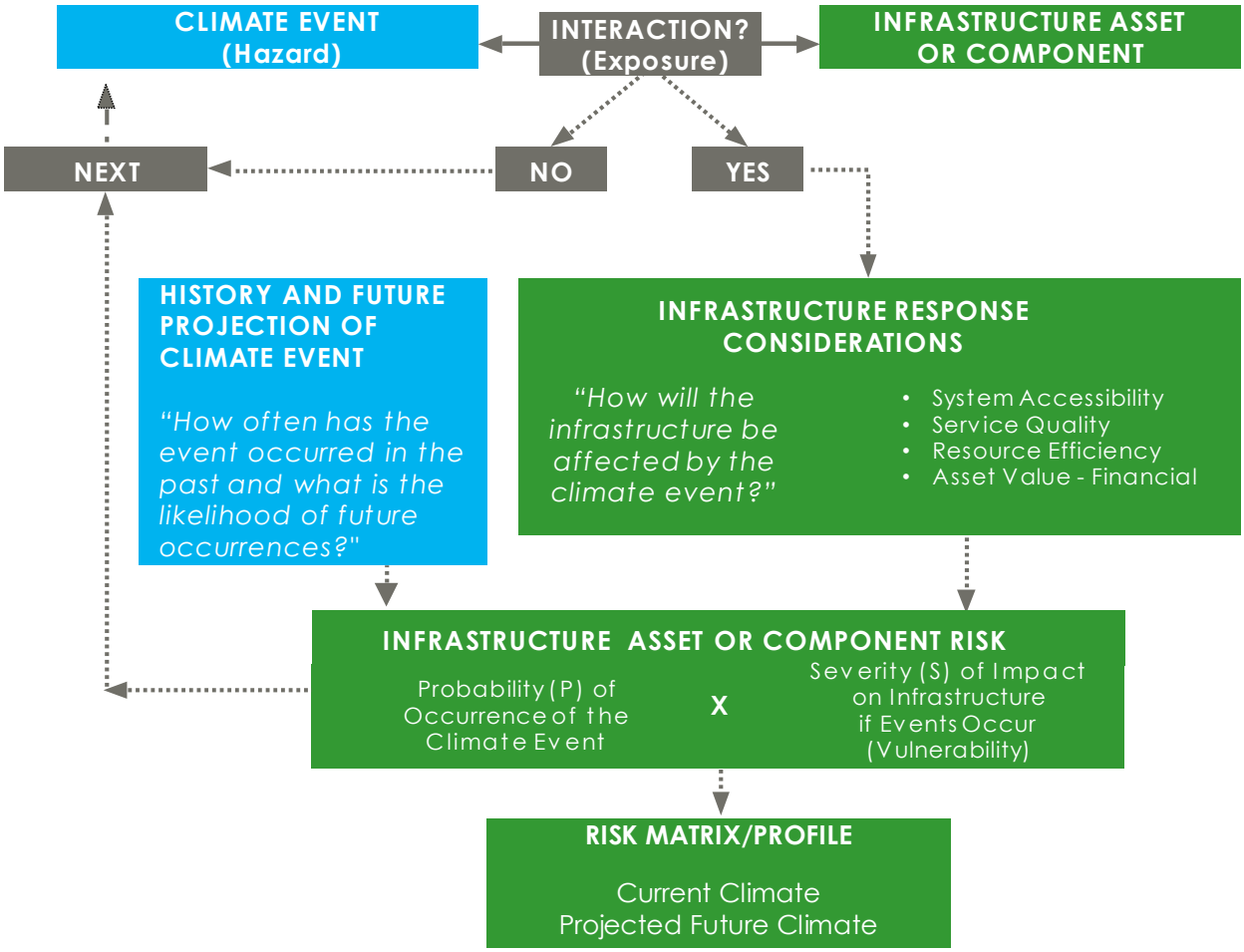


Figure 13 Flow Chart Descripting Risk Evaluation Process

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.

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.

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:

- Sa/Ra: Level of Service: System Accessibility
- Sq/Rq: Level of Service: Service Quality
- Se/Re: Resource Efficiency
- Sf/Rf: Asset Value - Financial

Asset/Infrastructure Element	Climate 1									Climate 2								
Current Climate	Daily maximum temp. of 35°C and higher									Daily maximum temp. of 40°C and higher								
	Probability = 3									Probability = 2								
	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.

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 Wild Fires

Wildfires can occur due to various combinations of natural and/or man-made events, and aggravated by factors such as high winds that spread the fires across large areas. Hydro Ottawa has policies and procedures in place for vegetation control along its distribution lines and corridors and around its substations and major equipment components.

Potential actions to mitigate wild fires risks, reviewing existing policies and procedures in regard to vegetation control, and possible changes in these will be assessed in the next phase of the study.

5.5.1.3 Invasive Species

The impacts of invasive species on Hydro Ottawa's assets and operations retained by the assessment team concerned the emerald ash borer and giant hogweed.

- In regard to the emerald ash borer, the assessment team identified this as a risk to trees close to lines and equipment that, if infected, would be weaker and could cause damages under less intense meteorological events than healthy trees. As winter temperatures become warmer in the future, it is likely that the emerald ash borer larvae would survive winters increasing the potential of weakening trees near Hydro Ottawa infrastructure.

  Potential actions to mitigate these risks and adaptation to future ash borer infestations will be assessed in the next phase of the study.

- Giant hogweed is described by the City of Ottawa (https://ottawa.ca/en/residents/water-and-environment/plants-and-animals/invasive-species) as “a serious invasive plant that poses a moderate threat to human health and safety. Giant Hogweed is primarily found along roads, streams and open areas. Plants reproduce well on disturbed sites, and prefer full sun and open habitat common along roadsides and ditches in rural areas. This plant is poisonous. Hollow stem, leaves and plant hairs produce a sap if broken. Sap can cause serious skin inflammation on contact. If contaminated skin is exposed to sunlight a more serious reaction can occur including blisters, discoloration, and scars. If sap has contact with eyes, loss of vision, blindness or damage to eyes can occur.”

  Giant hogweed, which was first reported in the Ottawa area approximately 10 years ago (see: https://www.cbc.ca/news/canada/ottawa/toxic-weed-discovered-in-ottawa-1.883529) requires precautions from Hydro Ottawa crews that work in an area – particularly along roads and ditches) where this plant is present are required to take precautions.

6.0 SUMMARY OF THE RISK PROFILE

This section presents the risk profile for Hydro Ottawa electrical distribution infrastructure and third-party assets from the perspective of climate change within the Hydro Ottawa service territory.

As indicated earlier in this report, the risk scores in the table below are the sum of the individual risks related to each of the infrastructure performance criteria selected by the project team; these criteria are:

- Level of service - system accessibility
- Level of service - service quality
- Resource efficiency
- Asset value - Financial

6.1 HIGH AND VERY HIGH RISKS

The significant current and future climate related risks (High: 31 – 60; Very High: ≥ 61 – these are highlighted in bold, red in the table) to the infrastructure identified by the assessment team are presented in the Table 12 below.

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 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.
- Freezing rainstorms 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.

Table 12 Significant Current and Future Climate Related Risks

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Daily maximum temp. of 40°C and higher	Operators Powerline Maintenance Staff	26 26	**65** **65**	Resource Efficiency Asset Value - Financial	• Potential heat stress impacts on personnel working outdoors. • Exacerbated by humidex.	• Health and safety concerns requiring precautionary measures such as more frequent resting periods, hydration, etc. • Delay in restoration • Loss in productivity
Annual wind speeds of 120 km/hr or higher (30-year occurrence)	Operators Powerline Maintenance Staff	36 36	36 36	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards	• Health and safety concern for personnel working outdoors
	Power Distribution: East-West lines and poles	**81**	**81**	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage to poles and lines from high wind events. • Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines • Impact on scheduling/productivity/ resources • Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines
	Power Distribution: North-South lines and poles	**108**	**108**	Level of Service: System Accessibility Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage to poles and lines from high wind events. • Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines • Impact on scheduling/productivity/ resources • Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines

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DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Summary of the Risk Profile
November 11, 2019

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	North-South lines and poles	32	32	Level of Service: System Accessibility Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Guy wires in legacy north-south lines are installed to support against prevailing westerly winds; poles and lines are therefore damaged from to high easterly winds • Risk of damages from falling trees or broken tree limbs.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines • Public safety concern is falling branches • Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines
Ice accumulation of 40mm (30-year occurrence)	Third Party Services and Interactions: Hydro One	54	72	Level of Service: Service Quality Asset Value - Financial	• Loss of supply to Hydro Ottawa Damages to poles shared between Hydro One and Hydro Ottawa • Loss of transmission • Loss of redundancy • Damage to equipment	• Disruption of service • Inability to restore service • Loss of redundancy • Loss of efficiency • Potential damage to Hydro Ottawa equipment (attached to Hydro One poles) • Damage to shared facilities
	Administrative and Operational Buildings	24	32	Resource Efficiency Asset Value - Financial	• Access to the building is hindered due to heavy ice accumulation • Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof • Ice accumulation on building mounted equipment (roof, exterior walls)	• Health and safety concerns for staff, contractors and/or public • Potential structural and/or functional damage to roof elements (e.g., membrane on flat roofs) • May result in blocked roof drains • Possible ice damming • Potential loss of assets • Reduced efficiency and/or functionality, and failure of equipment affected
	Substations - Buildings and Structural Components	24	32	Resource Efficiency Asset Value - Financial	• Access to the building is hindered due to heavy ice accumulation • Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof • Ice accumulation on building mounted equipment (roof, exterior walls)	• Health and safety concerns for staff, contractors and/or public • Delay in restoration • Potential structural and/or functional damage to roof elements (e.g., membrane on flat roofs) • May result in block drains • Possible ice damming • Potential loss of assets • Disruption of service • Reduced efficiency and/or functionality, and failure of equipment affected
	Operators Powerline Maintenance Staff	39 39	52 52	Resource Efficiency Asset Value - Financial	• Difficulty accessing areas needing repair due to icy conditions; e.g., ice on roadways and walkways, equipment.	• Potential delays in arriving to work site • Potential delays in performing work due to ice accumulation on equipment • Health and safety concerns

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Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
	Power Distribution: East-West lines and poles	51	68	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage from increased weight on overhead lines • Ice falling off of lines • Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure and uneven ice accretion could cause swinging or 'galloping' in the lines • Damage to poles and attached equipment • Damages to lines from fallen trees or broken tree limbs • Damage to poles and other surface equipment from vehicles losing control on icy roads	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines • Potential for flashovers • Ice break-up from lines may cause public safety concerns • Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines • Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines • Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines
	Power Distribution: North-South lines and poles	36	48	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage from increased weight on overhead lines • Ice falling off of lines • Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure and uneven ice accretion could cause swinging or 'galloping' in the lines • Damage to poles and attached equipment • Damages to lines from fallen trees or broken tree limbs • Damage to poles and other surface equipment from vehicles losing control on icy roads	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines • Potential for flashovers • Ice break-up from lines may cause public safety concerns • Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines • Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines

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DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Summary of the Risk Profile
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Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
						• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines

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6.2 MODERATE RISKS

The moderate current and future climate related risks (risk ratings 12-25) to the infrastructure identified by the assessment team are presented in the Table 13 below. These risks are presented here as a lower priority relative to those that were presented under Section 6.1.

Moderate risks include impacts due to high temperatures on buildings, ice accretion on load break switches, the risk of flashovers and pole fires during fog events, damages to civil structures from increasing freeze-thaw events, and the impacts of mid-level winds on poles and maintenance staff.

Table 13 Moderate Current and Future Climate Related Risks

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Daily maximum temp. of 35°C and higher	Administrative and Operational Buildings	12	20	Asset Value - Financial	• Increased cooling demands for the building critical systems (e.g., communication and IT systems).	• Capacity of cooling system may not be adequate to maintain ambient temperature within the design range of equipment affected which can lead to loss of efficiency, functionality or failure
Daily maximum temp. of 40°C and higher	Administrative and Operational Buildings	8	20	Asset Value - Financial	• Increased cooling demands for the building critical systems (e.g., communication and IT systems).	• Capacity of cooling system may not be adequate to maintain ambient temperature within the design range of equipment affected which can lead to loss of efficiency, functionality or failure
	Underground Cables	10	25	Level of Service: Service Quality Asset Value – Financial	• High ambient temperatures in combination with the heating of cables resulting from increasing electrical loading (for example from higher demands from A/C units) may cause an exceedance of the cables' temperature thresholds, particularly in areas were insulating ground cover is limited or non-existent (i.e. civil structures, bridges, etc.).	• Additional strain on, and limits to the underground electrical infrastructure capacity.
Ice accumulation of 40mm (30-year occurrence)	Substations: Station Load Break Switch	18	24	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Ice accretion on load break switches could result in difficulty transferring loads.	• Removal of ice required for the switch to be operable • Delay in restoration
Season with ≥ 50 fog days (Nov.-March)	Power Distribution: East-West Poles	18	24	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns
	Power Distribution: North-South Poles	18	24	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns
	Power Distribution: North-South - Fused Cut Out	12	16	Level of Service: System Accessibility Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Insulator breakdown on fused cut outs. • Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns
Freeze-thaw cycles – Daily Tmax/Tmin temp. fluctuation of ±4°C around 0°C	Power Distribution: Underground - Civil Structures	16	24	Resource Efficiency Asset Value - Financial	• Water penetration into or around civil structures which freezes causing stress on material	• Deterioration and damage (short- and long-term) to materials. • Uplift of near-surface infrastructure causing higher risks of damage during winter maintenance (e.g., snow removal) operations
Easterly winds of 80 km/hour or higher (cool season [Oct.-March])	Operators Powerline Maintenance Staff	24	24	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards	• Health and safety concern for personnel working outdoors
	Power Distribution: East-West Lines and Poles	24	24	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage to poles and lines from high wind events. • Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets • Disruption of service • Impact on scheduling/productivity/ resources • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines

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6.3 EXTERNAL RISKS

Through the interview and workshop processes, several external risks were brought to light. These were listed as “Third Party Services and Interactions” in the risk worksheet. External risks identified through this assessment are summarized below:

- Hydro One: power supply, shared infrastructure, attached equipment;
- City of Ottawa: stormwater drainage, winter maintenance;
- Telecommunications: Bell and fibre lines;
- Fuel Supply;
- Hydro Ottawa Subsidiaries: Energy Ottawa, Envari; and,
- Emergency Resources: mutual assistance partners, logistics (food services and lodging).

Managing many of these risks can be a challenge for Hydro Ottawa as in most cases, they have no direct control over the management of these third-party infrastructure elements and services. A discussion on how to address external risks presented in the adaptation report.



7.0 NEXT STEPS

This climate risk and vulnerability assessment represents the first component of a two-part study. The second part of the study will address risk meditation and adaptation recommendations for Hydro Ottawa to help them adapt to future climate risks and facilitate continuous improvement in their electrical distribution and supporting infrastructure.



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Appendix A CLIMATE CHANGE HAZARDS REPORT



RISK SCIENCES INTERNATIONAL

REPORT

Hydro Ottawa Climate Vulnerability Risk Assessment

Prepared for:
Hydro Ottawa

24 May 2019

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1. Climate Data and Analysis

Changes in climate, as reflected in long-term trends and in increases in both frequency and intensity of extreme weather events, are expected to cause a wide range of potentially costly and disruptive impacts to Hydro Ottawa's electrical distribution system, services, and operations. Hydro Ottawa's 1,116 km^2 service area includes both the City of Ottawa and the Village of Casselman (**Figure 1**) and services over 330,000 customers. Hydro Ottawa is the largest local distribution company in eastern Ontario. Having a strong environmental commitment, Hydro Ottawa recognizes the need to lead by example by implementing climate adaptation and resilience into its own assets and operations. In order to assess the resiliency of Hydro Ottawa's electrical distribution system, this project undertakes a distribution system climate vulnerability risk assessment (CVRA). The results of this project will inform the development of a Climate Change Adaptation Plan and help drive continuous improvement to Hydro Ottawa's Asset Management System.

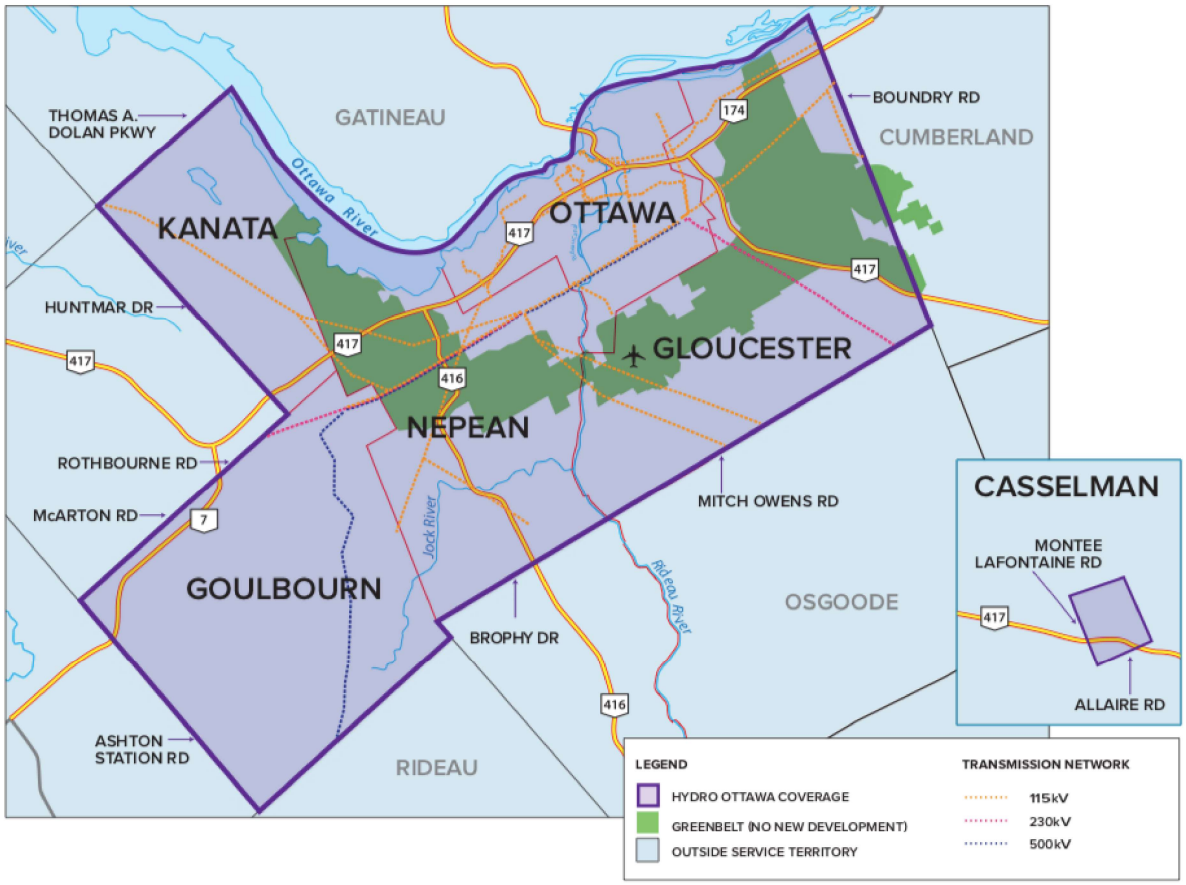


Figure 1: Map of the Hydro Ottawa service area in the City of Ottawa and Village of Casselman regions. Areas shaded in purple represent the Hydro Ottawa service area, while those shaded in blue are outside of its jurisdiction. The Ottawa Macdonald-Cartier International Airport, located in the Gloucester Ward, is also indicated. Figure from Hydro Ottawa, 2018a.

The IPCC defines risk as: "the potential for consequences where something of human value (including humans themselves) is at stake and where the outcome is uncertain". Risk is often represented as the probability of occurrence of hazardous events or trends multiplied by the consequences if these events

occur (IPCC, 2014a). Risk can be further understood as the interaction between vulnerability, exposure, and hazard (IPCC, 2014b). A hazard is the potential occurrence of an event, trend, or physical impact, which results in damage to something of human value. This could include, but is not limited to, infrastructure, livelihoods, ecosystems, and human health impacts.

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, reduced service life for asset components and for assets themselves, and the service life for the asset itself, and increased stress to systems and operations. Subsequent impacts can result in higher repair and maintenance costs, loss of asset value, and interruption of services or production housed by impacted assets, among others.

The development of climate data for this climate vulnerability risk assessment of Hydro Ottawa's distribution system involved three main activities:

- Identification of climate parameters (e.g. temperature, precipitation, winds) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Projecting the probability of occurrence of climate hazards for future climate (i.e. 2050s); and
- Converting 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 following subsections, following an overview of the local climate of the Greater Ottawa Region. Additionally, forensic analyses of three high impact events that affected the Hydro Ottawa distribution system in 2018 are provided.

1.1 Climate Data Sources

1.1.1. Baseline Climate: Historical Conditions

The baseline climate refers to the current and historical conditions. Climate data sources for this study include the most recent Environment and Climate Change Canada (ECCC) issued "Climate Normals" for the official averaging period of 1981-2010. In most cases, climatological analyses were completed using data from the ECCC climate data archive from the Ottawa Macdonald-Cartier International Airport meteorological station (**Figure 1**) and the Russell meteorological station. In most cases, the differences between the two stations were such that the Ottawa Airport station was used as the main data source. The Ottawa Airport station provides a long-term uninterrupted set of climate observations with hourly and daily data available to complete the analyses of most climate parameters. Rate-of-rainfall and extreme precipitation analyses are, however, challenged by an out-of-date intensity-duration-frequency (IDF) curve (only updated to 2007) for the Ottawa Airport state. This out-of-date record does not accurately reflect current climate conditions (e.g. missing notable extreme rain events in recent years). Therefore, climate analyses skills and experience are needed for the analyses and careful interpretation of extreme events over the baseline (current and historical) period climate information.

When required, separate datasets and specialised studies were consulted to address localised and high impact events, i.e. parameters which are difficult to observe using standard meteorological instrumentation and methods (e.g. tornadoes and lightning strikes). For instance, the national tornado database (Cheng et al., 2013) and the Canadian lightning detection network (Shephard et al., 2013) were used in the analyses of the tornado and lightning climate parameters, respectively. Specialised datasets and studies were combined with quantitative analyses and expert meteorological judgment to complete evaluation of the baseline conditions of the complex or rare events.

1.1.2. Climate Change Projections

1.1.2.1. CMIP5 Climate Models and the Delta Approach

The most authoritative source of climate change projections is the UN-supported Intergovernmental Panel on Climate Change (IPCC). Climate change projections of temperature- and precipitation-based parameters for this study were derived from an ensemble of 37 Global Climate Models (GCMs) for the most recent IPCC 5th Assessment Report (AR5; IPCC, 2013) (**Table 1**). In this assessment, the 37 GCMs, some with multiple runs per model, resulted in approximately 75 projection estimates from which to calculate possible future conditions. The use of multiple models to generate a 'best estimate' of climate change (multi-model ensembles) is preferred over a single or few individual model outcomes since each model can contain inherent biases and weaknesses and constructing multi-model ensembles can reduce and inform on the uncertainties in the climate projections (IPCC-TGICA, 2007; Tebaldi and Knutti, 2007). Maximum, minimum, and mean temperatures are standard output variables from these GCMs, as is mean precipitation.

Table 1. CMIP5 Global Climate Models (GCMs) used in this study.

Model Name (# of runs)	Organization	Country	Organization Details
ACCESS1-0 (1)	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS1-3 (1)	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM1-1 (1)	BCC	China	Beijing Climate Center, China Meteorological Administration
BCC-CSM1-1-M (1)	BCC	China	Beijing Climate Center, China Meteorological Administration
BNU-ESM (1)	GCESS	China	College of Global Change and Earth System Science, Beijing Normal University
CanESM2 (5)	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CCSM4 (6)	NCAR	US	National Center for Atmospheric Research
CESM1-BGC (1)	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CESM1-CAM5 (3)	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CMCC-CESM (1)	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CM (1)	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CMS (1)	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM5 (1)	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CSIRO-Mk3-6-0 (10)	CSIRO-QCCCE	Australia	Commonwealth Scientific and Industrial Research Organisation in collaboration with the Queensland Climate Change Centre of Excellence
FGOALS-g2 (1)	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FGOALS-s2 (1)	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FIO-ESM (3)	FIO	China	The First Institute of Oceanography, SOA, China
GFDL-CM3 (1)	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2G (1)	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2M (1)	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GISS-E2-H (1)	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-H-CC (1)	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R (1)	NASA GISS	US	NASA Goddard Institute for Space Studies

Model Name (# of runs)	Organization	Country	Organization Details
HadGEM2-AO (1)	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-CC (3)	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-ES (4)	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
INMCM4 (1)	INM	Russia	Institute for Numerical Mathematics
IPSL-CM5A-LR (4)	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5A-MR (1)	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5B-LR (1)	IPSL	France	Institut Pierre-Simon Laplace
MIROC-ESM (1)	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC-ESM-CHEM (1)	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC5 (3)	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM-LR (3)	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MPI-ESM-MR (1)	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MRI-CGCM3 (1)	MRI	Japan	Meteorological Research Institute
NorESM1-M (1)	NCC	Norway	Norwegian Climate Centre

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 2**).

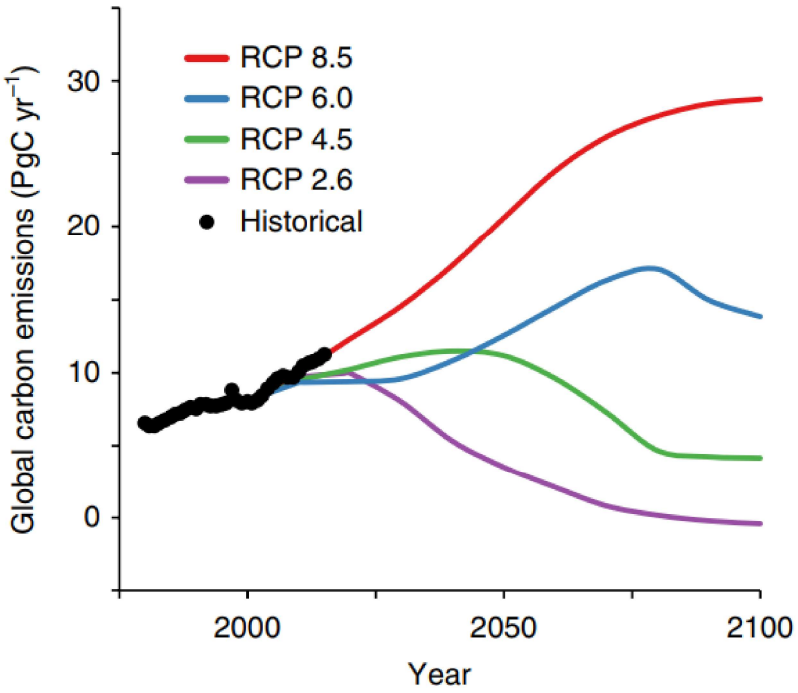


Figure 2. Historical CO2 emissions for 1980-2017 and projected emissions trajectories until 2100 for the four Representative Concentration Pathway (RCP) scenarios. Current global emission trends have very closely followed the "business-as-usual" RCP8.5 scenario trajectory. Figure from Smith and Myers, 2018.

In this study, the "Delta Approach" is used to generate localised 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, is easy to understand, and has widespread use in impact and adaptation studies. The Delta Approach consists of 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**.

1.1.2.2. Specialised 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 specialised 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 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.

1.1.2.3. 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.

1.1.2.4. Professional Judgment

"Perfect" or "ideal" information and data for given hazard usually do not exist, and assessments always require the application of professional judgment from interdisciplinary teams to make use of the data and information available. While sometimes referred to as a *source* of risk assessment information, professional judgment is better characterised 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 judgment 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 judgment 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.

1.2 Identification of Climate Parameters and Thresholds

The climate parameters and thresholds established for analysis in this study were assembled and analysed 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 2**, 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 in **Table 2**.

Table 2: Identified climate parameters and thresholds used in this study, along with an overview of performance considerations and rationale for selection.

Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Temperature			
Extreme Heat	$T_{max} \geq 25°C$	**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	• Tmax ≥ 30°C identified as a personnel issue; • Tmax of 40°C used as a design value; • Higher temperature thresholds lead to extra loading on the system from increased commercial and residential air conditioner use; • Thermal stress can result in cracking and fissuring in materials (e.g. polymer-based materials).
	$T_{max} \geq 30°C$		
	$T_{max} \geq 35°C$		
	$T_{max} \geq 40°C$	**Asset Value** – High temperature operating threshold	
	$T_{mean} \geq 30°C$	**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 $T_{max} \geq 30°C$ and $T_{min} \geq 23°C$	**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	• System overloading common after 3 days of consecutive heat due to high demands on electrical grid (e.g. transformers) by increased air conditioning use; • Equipment unable to cool properly reducing functionality.
	Consecutive Days with $T_{max} \geq 30°C$ and $T_{min} \geq 25°C$		
Extreme Cold	$T_{min} \leq -35°C$	**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	• Identified as a personnel issue; • Older sections of Ottawa may experience overcapacity due to extensive use of electric baseboard heating;

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Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
			• Tmin of -40°C used as a design value; • Extreme cold can result in underperformance of vehicles and outdoor infrastructure.
Rain			
Extreme Rain	50 mm in 1 hour	**Level of Service** – Localised flooding; flooding of low-lying areas and subterranean infrastructure (e.g. underground vaults) possible	• Design threshold; • Hydro Ottawa personnel have indicated extreme rainfall has not significantly impact Hydro Ottawa infrastructure, although low-lying equipment, such as vaults, may be more vulnerable (particularly in older neighbourhoods); • Extreme rain can result in reduced accessibility to assets (e.g. flooded roadways).
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); • Pole fires and flashovers possible during freezing rain events; • Most common damage to infrastructure related to ice accretion and accumulation on
	40+ mm	**Asset Value, Level of Service, Resource Efficiency** – Major and widespread outages possible; prolonged events	

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Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
			tree branches and resulting breaks; • Combined ice accretion and wind is a concern.
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 collars, 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 easterly winds (lines are guyed for protection from prevailing westerly winds) (e.g. Greenbank Road, Fisher Avenue, Limebank Road); • Potential damage to infrastructure due to tree and limb falls and wind-swept
	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
			debris and reduced access due to debris deposits
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) EF1+ point probability (i.e. tornado striking a specific asset, e.g. a substation, in the City of Ottawa service area)	**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).

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Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
Invasive Species			
Emerald Ash Borer (EAB)	$T_{min} \leq -30°C$	**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; • Tmin ≤ -30°C is the kill threshold for EAB mature, non-feeding larvae.
Giant Hogweed	3 Days $T_{max} \leq -8°C$	**Level of Service** – Significant human health risk upon exposure	• Upon contact, a severe occupational hazard for workers – sap can cause serious skin inflammation on contract, 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 Tmax ≤ -8°C required for germination of Giant Hogweed seeds.
Fog			

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Climate Parameter	Thresholds	Performance Considerations	Selection Rationale
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.
Frost			
Freeze-thaw Cycles	Daily T_{max} T_{min} temperature fluctuation around 0°C	**Asset Value –** Freeze-thaw cycles can result in weathering and damage to hard infrastructure (minimum of 30 cycles/year required to damage concrete) **Level of Service** – Freeze-thaw cycles can lead to icy conditions which become a health and safety concern	• Hydro Ottawa personnel have noted more mid-winter events, resulting in more pole fires; • Freezing moisture known to cause failure in underground cabling, has increased incidents of pole fires, and limits access by crews; • Associated thermal stresses and frost weathering can result in cracking and fissuring in materials (e.g. polymer-based materials); • Large temperature ranges in freeze-thaw cycles can result in increased weathering and damage.
	Daily T_{max} T_{min} temperature fluctuation of ±4°C around 0°C		

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1.3 Greater Ottawa Region Climate Profile

As with the rest of globe, Canada, and Southern Ontario, the climate of the Greater Ottawa Region has been changing. **Figure 3** 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 colouration) 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 4**). The long observation record at the Ottawa Airport weather station (1939-present) further indicates the overall increase in temperature (OCCIAR, 2011a). 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, 2011a) 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, 2011a) 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).

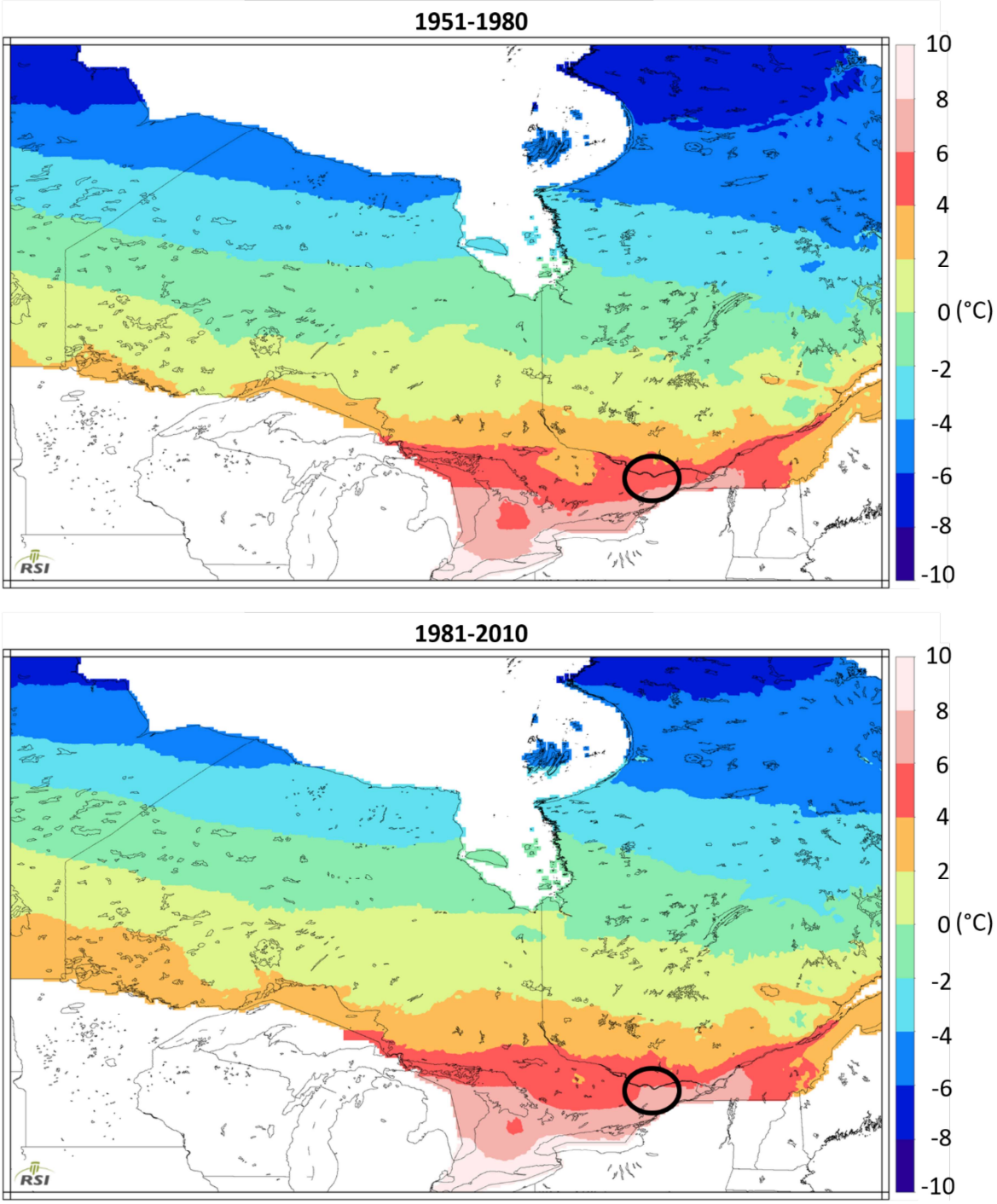


Figure 3. Observed annual mean (2m) air temperature over the 1951-1980 (upper) and 1981-2010 (lower) periods. The change in mean annual temperature can be inferred from comparison of the plots (i.e. the difference in the colouration), with observed increases in temperature throughout Southern Ontario. 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.)

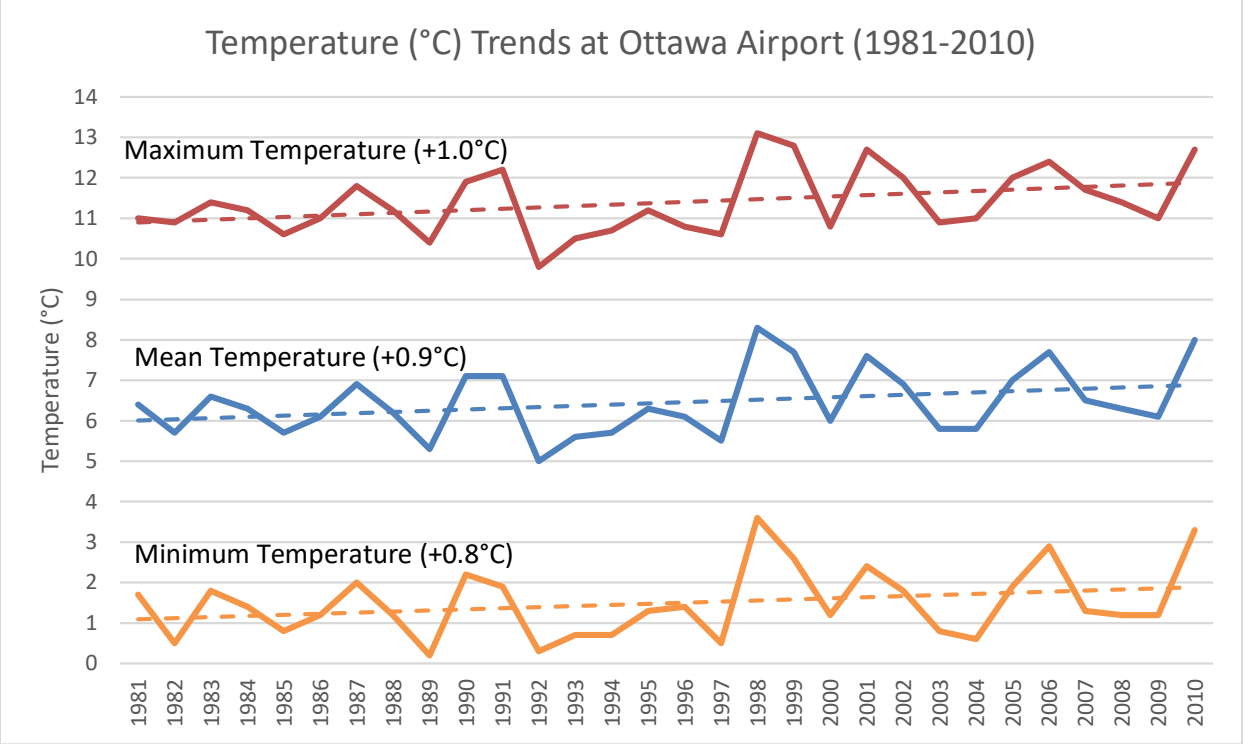


Figure 4. 1981-2010 annual mean, maximum, and minimum temperature data and trends at Ottawa Airport.

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 5**). 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, 2011a). 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, 2011a), 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.

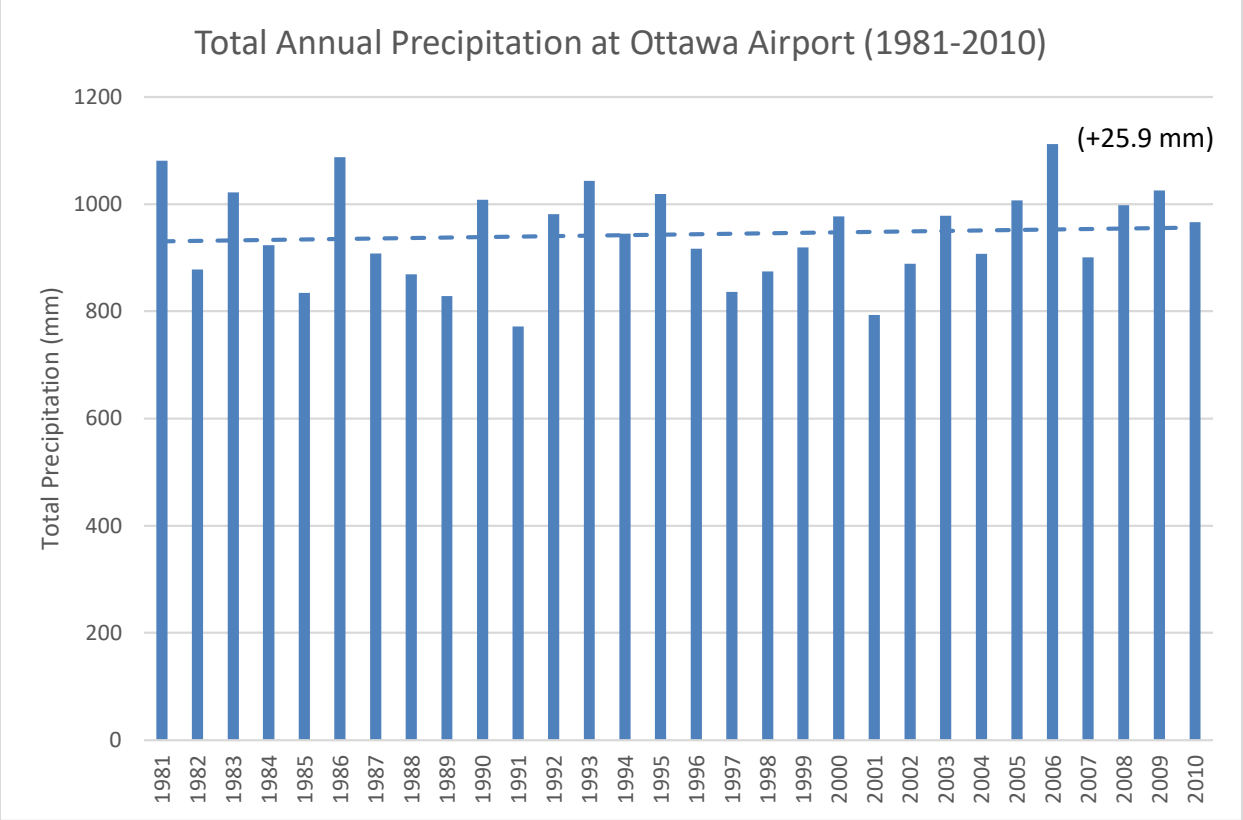


Figure 5. 1981-2010 total annual precipitation data and trend at Ottawa Airport.

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). 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 6**) (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 6**), 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.

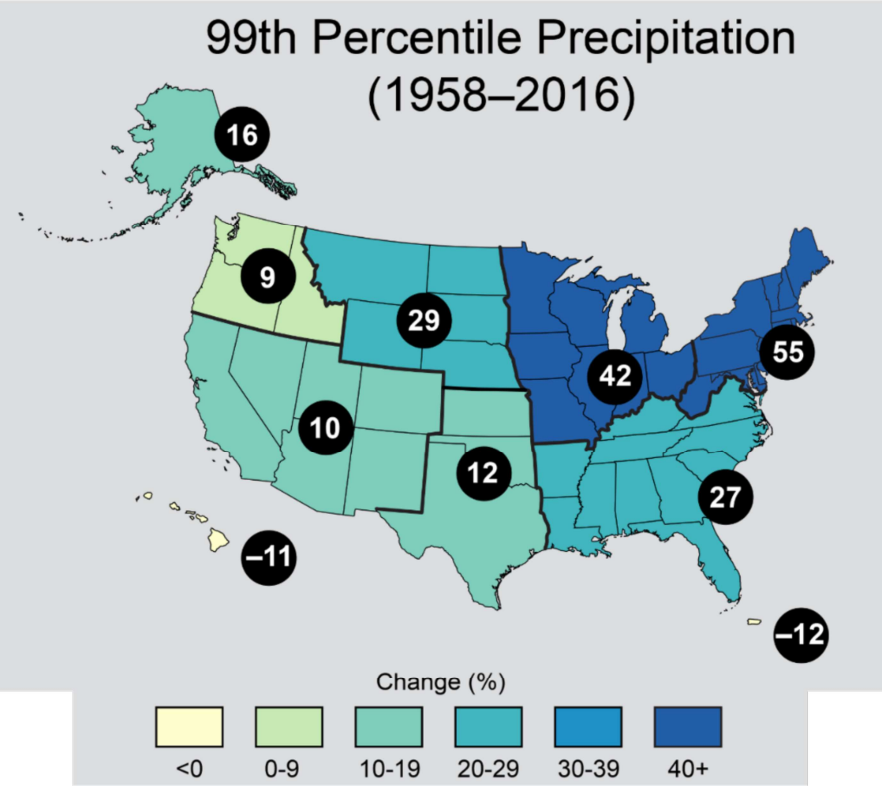


Figure 6. Percent increases in the amount of precipitation falling in daily events that exceed the 99th percentile of all days with precipitation (i.e. the total precipitation falling in the top [heaviest] 1% of daily precipitation events) in the United States, 1958-2012, calculated from daily precipitation 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 (Klaassen et al., 2003) 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, affecting the Greater Ottawa Region since 1940, including the most recent April 2018 event as well as the infamous January 1998 ice storm. 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 develop in northeastern North America over the past ~40 years.

Under climate change, observed trends are projected to continue. **Table 3** outlines general projected changes in climate parameters of interest to Hydro Ottawa's electrical distribution system, services, and operations

Table 3. Summary of potential climatic changes in the Greater Ottawa Region.

Climate Parameter	Projected Changes
Temperature – Extreme Heat	• Increased frequency and intensity • Increased frequency and length of heat waves
Temperature – Extreme Cold	• Decreased frequency and intensity • Occurrence of extreme cold outbreaks ("Polar Vortex" winters) likely to continue
Rain (Short Intensity – High Duration)	• 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	• Increased frequency • Increased winter season (e.g. January) events
Snow	• Likely decrease in annual total accumulation • Continued occurrence and steady frequency of larger individual events
High Winds	• Slight increase in frequency of high wind events (e.g. 90 km/hr; 120 km/hr)
Lightning	• Increased frequency (by about 12% per degree Celsius of warming) • Increased length of the higher frequency lightning season
Tornadoes	• 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	• Likely increase
Frost (Freeze-Thaw Cycles)	• Decrease in annual total number of freeze-thaw days • Increase in monthly totals in the shoulder seasons (e.g. November and March)

1.4 Forensic Analyses of Three High Impact Events

1.4.1. Climate Event Forensic Analysis

Individual high-impact severe weather events can produce disproportionate amounts of damage to electrical distribution systems. These events test the limitations and capacity of response crews, often requiring a "triage process" to prioritize repairs by their criticality to the distribution system, potentially 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.
- **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. A much more detailed description of forensic assessment methodology, and case study analyses and results are provided in **Appendix B**. Adaptation recommendations will be the subject of an upcoming portion of the risk assessment project and will therefore be provided at a later date.

1.4.2. 15 - 16 April 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.

Because combined loading from wind and ice are challenging, efforts have been made in other jurisdictions to estimate the potential impacts from various combinations of wind and ice loads. However, the Sperry-Piltz Ice Accumulation (SPIA) Index (Figure 7), a combined ice and wind load scale which is becoming popular among meteorologists and contains 6 categories of increasing severity, ranging from 0-5. However, this event would have been ranked a “4” on the 0-5 scale, corresponding to much more severe impacts than what was observed during this event. 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.

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.

The Sperry-Piltz Ice Accumulation Index, or "SPIA Index" – Copyright, February, 2009

ICE DAMAGE INDEX	* AVERAGE NWS ICE AMOUNT (in inches) *Revised-October, 2011	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 7. 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.

1.4.3. 4 May 2018 High Wind Event

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 8). 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 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.

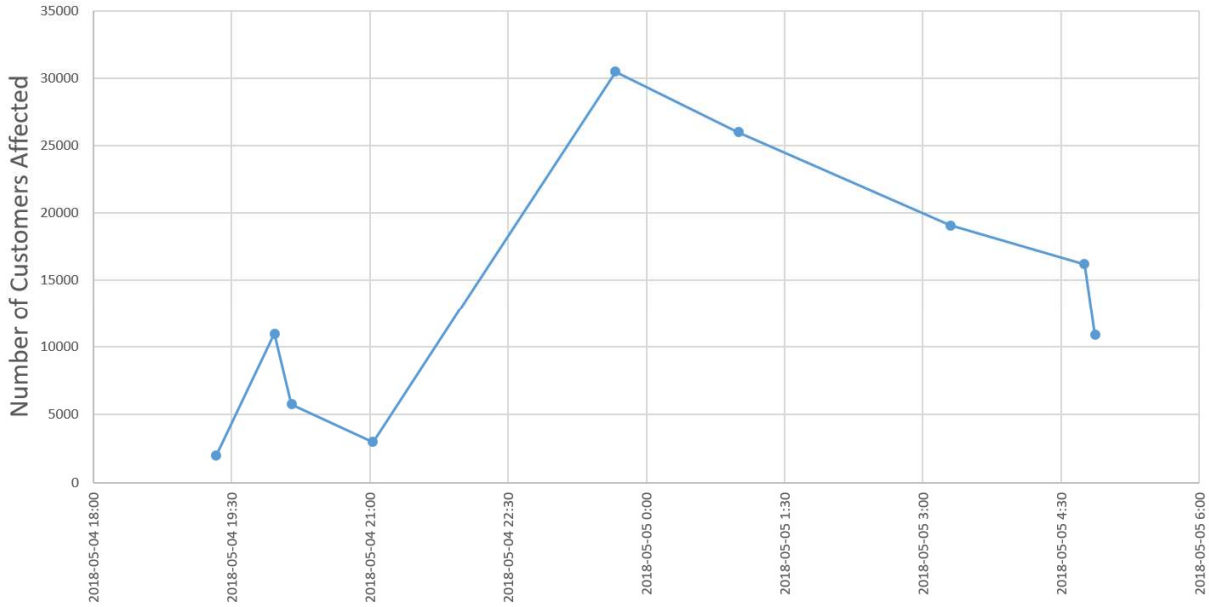


Figure 8. Timeline describing number of customers affected during May 4, 2018 wind storm. Note small peak of ~11,000 between 7:30 and 8:00 PM EDT, followed by much larger peak of >30,000 later in the evening. Total number of customers affected based on outages reported by Hydro Ottawa's Twitter account.

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.

1.4.4. 21 September 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 EF3 on the 0 to 5 EF-scale of tornado intensity, and the Nepean-South Ottawa tornado, rated EF2. 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 207,000 customers being affected, occurred in a time span of approximately 38 minutes (Figure 9).

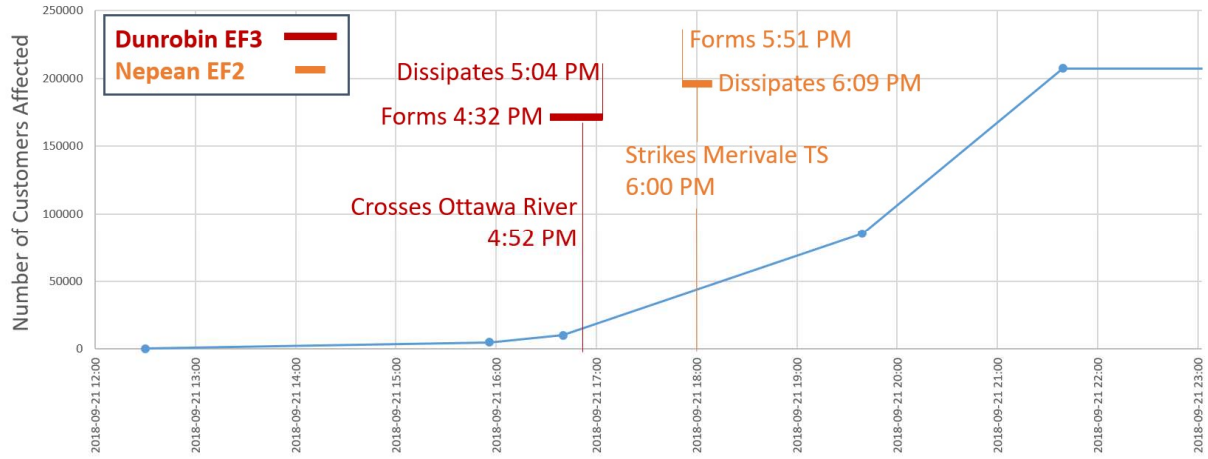


Figure 9. Timeline comparing the total number of reported customers affected versus the occurrence of the Kinburn-Dunrobin-Gatineau tornado (red) and the Nepean-South Ottawa tornado (orange). Outage totals are based on those reported by Hydro Ottawa's Twitter account and the final total based on post-event reports.

Based on a review of historical events, this appears to be the first day in recent history in which two significant (i.e., EF2 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 EF1 intensity when these impacts occurred, suggesting maximum winds of around 170 km/h.

1.4.5. Case Study Based Recommendations

Details and elaboration regarding the case study based recommendations can be found in the detailed report on forensic analyses in **Appendix B**. We note that Hydro Ottawa after action reports also provide a number of recommendations for improving response and system resilience, those are not repeated here and can be found in Hydro Ottawa's after action reports relating to each of these events.

Operations, Maintenance and Monitoring

- ***Use of social media to enhance situational awareness before and during severe weather events:*** Many of Canada's leading weather forecasters, as well as its large and medium sized electrical utilities, maintain a social media presence, particularly on the Twitter platform. These accounts can be monitored to provide additional details on weather conditions as well as recent or ongoing impacts, which that can provide additional data and interpretation of weather information beyond standard publicly available weather forecasts, watches and warnings.
- ***Additional monitoring of key meteorological parameters within Hydro Ottawa's service area:*** Since many of the meteorological measures critical to impacts on electrical systems – particularly wind gust speeds and freezing precipitation ice accretion amounts – are not well monitored, Hydro Ottawa could enhance such monitoring through the installation of additional weather monitoring stations.
- ***Monitoring weather conditions and electrical distribution and transmission outages for locations "up-stream" of Hydro Ottawa's service area:*** Particularly for large scale, cool season weather events, up-stream utilities may be affected by the same weather system several hours prior to Hydro Ottawa's network being affected. Monitoring weather observations and local utilities in up-stream jurisdictions can help to provide early warning of incoming impacts, as well as providing some indication of the potential severity and duration of these impacts.
- ***Improved outage reporting systems:*** To further improve understanding of the sensitivity and resilience of the distribution system, and perhaps to better target and prioritise response during events, improvements to the outage reporting system could be investigated. Such improvements should aim to automatically report and record the exact timing, location, and number of affected customers for individual outage events.

Planning and Training

- ***Basic severe weather forecasting and awareness training for staff:*** Additional training and education of Hydro Ottawa staff would allow for better use of available weather observation information and forecast products. Such training can assist with better anticipation of the extent, type and severity of weather events and can also be leveraged to target portions of the system for response operations during and immediately following severe weather events, particularly during warm season events which tend to result in more localised and concentrated impacts on distribution networks.

System Management, Repair and Upgrades

- ***Review of/increased emphasis on tree trimming operations:*** A majority of impacts resulting from severe weather are due to tree contacts, and an emphasis on tree trimming can significantly reduce these impacts, particularly for events which would otherwise be well within the design load limits of overhead systems.
- ***Strategic equipment upgrades:*** As individual components are replaced due to age, damage, or critical vulnerability, they can be replaced with more robust and/or more easily repaired components. Over time, these strategic upgrades can increase the overall resiliency of the network.
    - ***Break-away connectors and other sacrificial components:*** These are one example of the type of component which can be used as a replacement for legacy equipment. These are specifically indicated in cases where widespread damage occurs to individual

customer connections, which tended to result in the longest outages for individuals affected by severe weather related power interruptions.

Event Specific Recommendations

- ***Development of tailored combined ice and wind impact scale for eastern Canada:*** Indices used to help forecast potential severe weather impacts – in this case, the SPIA Index for combined wind and ice loading – are currently being developed and refined but may require further tailoring to take into account differences in climate conditions and infrastructure design loading for different regions within North America. However, results of development and testing indicate that such scales can be very consistent in their ability to predict impacts for a series of wind and ice load combinations, and would be of great utility for impacts forecasting and event response.

1.5 Climate Probability Scoring for Risk Ranking

Statistical information for both historical (1981-2010) and projected (2050s) event frequencies of the identified climate parameters and the five-point scoring scale applied in Hydro Ottawa's Asset Management System Risk Procedures (**Table 4**) 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 4: Probability scoring scale used in Hydro Ottawa's Asset Management System Risk Procedures.

Probability Score	Descriptor	Detailed Description	Probability (p) 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 evaluates the probability of an event directly impacting the Hydro Ottawa service area with both the annual probability and probability over a 30-year period calculated. 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.

1.6 Climate Thresholds and Analytical Results

Historical baseline (1981-2010) and projected climate change (2050s) information under the RCP8.5 scenario for the identified climate parameters is presented. **Table 5** provides a summary table of the analytical results (annual and 30-year probabilities and scores). Included in **Table 5** are the relevant thresholds for each climate parameter, historical and projected annual frequency and probabilities, study period (30-year) probabilities, and the corresponding probability 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 (**Table 4**), are used to calculate risk values and will appear in the risk matrix summarizing the overall results of the risk assessment. Detailed discussions for each climate parameter are provided in **Appendix C**.

Table 5: 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)			
	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score
Temperature – Extreme Heat								
Daily maximum temp. of 25°C and higher	100% (~62-63 yr^{-1})	5	100%	5	100% (~99 yr^{-1})	5	100%	5
Daily maximum temp. of 30°C and higher	100% (~14-15 yr^{-1})	5	100%	5	100% (~42 yr^{-1})	5	100%	5
Daily maximum temp. of 35°C and higher	50% (< 1 yr^{-1})	3	>99%	5	100% (~6 yr^{-1})	5	100%	5
Daily maximum temp. of 40°C and higher	6% (< 1 yr^{-1})	2	84%	4	100% (~1-2 yr^{-1})	5	100%	5
Daily average temp. of 30°C and higher	3% (< 1 yr^{-1})	1	60%	3	100% (~1-2 yr^{-1})	5	100%	5
Heat wave: Consecutive days with $T_{max} \geq$ 30°C and $T_{min} \geq$ 23°C	7% (< 1 yr^{-1})	2	89%	4	100% (~2 yr^{-1})	5	100%	5
Heat wave: Consecutive days with $T_{max} \geq$ 30°C and $T_{min} \geq$ 25°C	0% (0 yr^{-1})	1	0%	1	37% (<1 yr^{-1})	3	>99%	5
Temperature – Extreme Cold								
Daily minimum temp. of -35°C and colder	3% (< 1 yr^{-1})	1	60%	3	0.1% (Rare)	1	3%	1
Rain								
50 mm of rainfall in 1 hour	1% (< 1 yr^{-1})	1	~25%	2	4.5% (< 1 yr^{-1})	1	75%	4
Freezing Rain & Ice Storms								

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Climate Thresholds	Baseline Probabilities				2050s Probabilities (RCP8.5)			
	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score
Ice accumulation of 25 mm	5% (< 1 yr^{-1})	1	79%	4	6% (< 1 yr^{-1})	2	84%	4
Ice accumulation of 40 mm	2.5% (< 1 yr^{-1})	1	>50%	3	3.8% (< 1 yr^{-1})	1	~70%	4
Snow								
Days with 5 cm or more of snowfall	100% (~15 yr^{-1})	5	100%	5	100% (~15 yr^{-1})	5	100%	5
Days with 10 cm or more of snowfall	100% (~5-6 yr^{-1})	5	100%	5	100% (~5 yr^{-1})	5	100%	5
Days with 30 cm or more of snowfall	13% (< 1 yr^{-1})	2	98%	5	10% (< 1 yr^{-1})	2	>95%	5
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
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
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
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
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

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Climate Thresholds	Baseline Probabilities				2050s Probabilities (RCP8.5)			
	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score
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
Annual wind speeds of 90 km/hr or higher	23% (< 1 yr^{-1})	2	>99%	5	29% (< 1 yr^{-1})	2	>99%	5
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
Lightning								
Strikes near infrastructure (flashes/ km^2/ year)	1.1% (< 1 yr^{-1})	1	28%	2	1.5% (< 1 yr^{-1})	1	36%	3
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
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
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

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Climate Thresholds	Baseline Probabilities				2050s Probabilities (RCP8.5)			
	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score	Annual Probability	Annual Probability Score	30-Year Probability	30-Year Probability Score
Giant Hogweed (3 consecutive days of -8°C or colder [gemination requirement])	100% (25 yr^{-1})	5	100%	5	100% (17 yr^{-1})	5	100%	5
Fog								
Season with ≥ 50 fog days (Nov.-March)	37%	3	100%	5	*Likely increase*	3-4	100%	5
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
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

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Appendix A: Delta Approach

The following presents the 5 steps of the Delta Approach and how it is used in this project. The Delta Approach is applied to temperature (maximum, minimum, and mean) and precipitation data.

Step 1 is completed using observational data (i.e. from the Ottawa International Airport weather station).

1. Obtain the baseline condition (or 'average' climate) for each climate variable at each of the chosen observation stations.
    - Climate conditions for the 1981-2010 (30-year) time period are used as the "Climate Normals", or baseline, for this project. This 30-year period is the current official "Climate Normals" period considered by ECCC.

The following three steps (Steps 2 to 4) are then completed for each individual CMIP5 model (i.e. the 'delta' is calculated for each individual model) using monthly data. For some of the 37 GCMs included, multiple projections have been produced and all available outputs (model runs) are considered. When a model has multiple runs, the individual model mean delta is calculated (i.e. deltas from all runs for the individual model are averaged) and is used when calculating the CMIP5 ensemble mean delta value (completed prior to Step 5).

2. Obtain the model average climate for the 1981-2010 time period for the observation station location.

3. Obtain the future climate projections for the observation station location, for the required future time period (i.e. 2050s), and the RCP emission pathway to be evaluated (i.e. RCP8.5). These projections will provide an overview of the average future conditions as projected by CMIP5 GCMs for the time period of interest.

4. The difference (or 'delta') between the modeled baseline (obtained is Step 2) and respective modeled future time period (obtained in Step 3) will then be calculated, representing the change in the specified climate conditions (the 'climate change signal'). Climate deltas will be produced for each modelled variable, relative to the 30-year baseline (1981-2010).

Once all individual CMIP5 model deltas have been calculated, the individual model deltas are averaged to obtain the overall CMIP5 ensemble mean value for the station location and is utilized in Step 5. Prior to calculating the CMIP5 ensemble mean, the individual model outputs are re-gridded to a common resolution since different modelling centres use different grid alignments and dimensions. This re-gridding uses a scale representative of the resolution of the GCMs (in this case approximately 200 km by 200 km) in order to match to the grid dimensions of the popular NCEP (National Centres for Environmental Prediction) reanalysis, and a resolution intermediate of all models. This is done using a process of linear interpolation to obtain the re-gridded datasets.

5. The final step is to apply the CMIP5 ensemble mean delta value calculated to the observed station data 1981-2010 baseline period value (i.e. the CMIP5 ensemble delta for the month is applied to the daily observational data accordingly). This has the effect of correcting for any difference (or

bias) between the true measured baseline climate and the CMIP5 projected baseline climate. By applying the delta to the true measured baseline, localized climate projections are generated for the future period and variables which can be directly compared against the observed 1981-2010 baseline data, along with information on the 'spread' (or range) of the model projections. Uncertainty can be approximated by considering the spread of the projections, with smaller ranges suggesting more confidence in the projected value(s) than a wide projection range. This approach also accommodates use of finer scale baseline climate information.

Once the Delta Approach has been completed, projected changes in the climate parameters are calculated by applying the chosen threshold(s) and using the CMIP5 ensemble-based climate projections generated in Step 5 and the observed 1981-2010 baseline.

Appendix B: Detailed Forensic Analyses of High Impact Weather Events

High Impact Event Forensics

Individual high-impact severe weather events can produce disproportionate amounts of damage to electrical distribution systems, with tens to hundreds of thousands of customers losing electrical power. These can result in in dozens of individual locations within the distribution network suffering damage in rapid succession, testing the limitations and capacity of response crews, often necessitating prioritization of repairs and leaving some customers without power for one or more days. However, by conducting investigations of these events, response strategies can be developed to increase the resiliency of the electrical distribution network and to reduce impacts in subsequent storms.

We note that Hydro Ottawa already conducts post-event forensic analyses of events, which is rare among utilities in Canada. These investigations have resulted in the development of a number of key recommendations for improved response and disaster planning, particularly regarding operations and response during and immediately following events. These are already available in detailed reports (Hydro Ottawa 2018b, 2018c and 2018d) and will not be repeated here.

The value added for the analysis conducted in conjunction with the PIEVC assessment includes the application of an understanding of atmospheric dynamics and physics related to severe weather events and associated processes. These are combined with investigations already conducted by Hydro Ottawa staff to provide an atmospheric science-based perspective on how to further analyse these high impact events with the ultimate goal of developing recommended action items, such as improved monitoring, identifying response strategies and improving overall resilience to severe climatic events.

Identification of Key Events

Hydro Ottawa pre-defined three high-impact severe weather events for investigative focus as part of the overall scope of the PIEVC assessment:

- April 15-16, 2018 combined ice and wind storm;
- May 4, 2018 wind storm; and,
- September 21, 2018 tornado outbreak.

The forensic assessment was conducted by combining and comparing information regarding both infrastructure impacts and meteorological data. The objective of the forensic analyses were to develop, for each event:

- **Occurrence Timelines –** Determine which impacts occurred when to understand the progression of events leading up to, during, and immediately following major storms resulting in widespread service outages.
- **Meteorological/Climate Hazard Diagnosis** – Determine the type, extent, and severity of weather/climate phenomenon responsible for outages. This includes the assessment of the relative contributions of weather and infrastructure characteristics to damage and failures, as well as a comparison to both historical cases and future climate change projections to better understand the true frequency and overall risk posed by these hazards.

- **Develop Adaptation Response Recommendations –** Develop recommendations for consideration in improving overall resilience and response to similar events.

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Methodology

Several sources of information were consulted for this analysis, including:

- News Media sources (e.g. Ottawa Citizen, CBC, CTV)
- Hydro Ottawa social media, specifically Twitter and news media press releases
- Hydro Ottawa post-event reports
- Meteorological observations (e.g. weather station data, weather radar)
- Historical climate data, including specialised data sets for extremes (i.e., ice storms, tornadoes)
- Relevant literature and design information (e.g. climatic loads from CSA standards)

These various sources of data and information are then combined to establish facts and hypotheses regarding the event under investigation.

April 15-16, 2018 Combined Ice & Wind Event

A combined wind and ice storm, which began in Ottawa around midday on April 15 and intermittently continued until midday April 16, resulted in a total of 73,797 Hydro Ottawa customers losing power. Leading up to this event, Environment and Climate Change Canada (ECCC) issued freezing rain warnings on April 14 for a large swath of southern Ontario, with up to 40 mm of freezing rain ice accretion possible between Windsor, the Muskokas, and east through to the Ottawa area, including the Greater Toronto and Hamilton areas (National Post, 2018). Ice accretion impacts were felt across southern Ontario and began a full day prior to the start of the event affecting Hydro Ottawa.

Ottawa airport reported a total of 16 hours of freezing precipitation between 12 PM EDT on April 15 and 10 AM April 16. The freezing rain and drizzle resulted in ice accumulations on overhead electrical infrastructure and adjacent vegetation and was accompanied by strong winds gusting to 67 km/h on April 15 and up to 74 km/h on April 16. Total estimated ice accumulations for April 15 were likely around 10 mm, which resulted in a small number of scattered outages within the service area. However, ice continued to accumulate overnight and into mid-morning. Between 7 AM and 2 PM on April 16, the total number of Hydro Ottawa service area outages (as reported via Hydro Ottawa's Twitter account) increased from approximately 4,000 customers to over 43,000 customers. Conditions were significant enough to down large trees by 10 AM, and entire line segments, consisting of rows of snapped utility poles carrying multiple circuits, were down by 11:30 AM.

In addition to trees and branches impacting lines, a total of 33 poles were snapped across the City during the event, including 16 in a north-south oriented segment along Limebank Road. The majority of affected customers had service restored by the afternoon of April 16, but a small number of customers who had suffered damage to individual grid connections remained out for much longer, with "less than 50" remaining out by 7 AM EDT on April 18.

April 2018 Event – Analytical Results

As with the May 4, 2018 wind storm (described below), significant damage occurred to utilities up-stream of Hydro Ottawa's network well ahead of any local outages. In this case, they began approximately one day prior to the event affecting Ottawa's distribution system. By April 15, the day ice accretion in the Ottawa area began and prior to major, city-wide damage to the system, Hydro One had already experienced damage across multiple regions within its rural electrical distribution network. An April 15 press release, with data up to 6:30 PM EDT, indicated 34,000 customers without power, as well ongoing damage associated with the eastward progression of the storm. Another 89,000 customers had already lost power and been subsequently restored. Impacts were reported in Algoma district, north of Lake Huron, as well as several in Hydro One service regions along a swath from southern Lake Huron to the north shore of Lake Erie and Golden Horseshoe Region (Hydro One Press Release, April 15, 2018). By April 16th, Hydro One reported that more than 200 poles, along with countless overhead wires, had been downed across the province, with many more customers affected in eastern Ontario's "cottage country" (i.e., Peterborough and Fenelon Falls) to the east of the Ottawa River Valley, as well as parts of southeastern Ontario south of Ottawa (Vankleek Hill and Winchester areas) (Hydro One Press Release, April 16, 2018).

Toronto Hydro suffered similar damage to Hydro Ottawa's network, reporting a total of over 44,000 customers affected (Toronto Hydro Press Release, April 16 12:35 EDT). Damage occurred over a span of 5 hours, beginning late in the evening of April 15th, with most outages occurring by 3 am on April 16, effectively lagging impacts to Hydro Ottawa's system by approximately 6-10 hours. Combined wind and ice loading was also indicated in the Toronto area (Toronto Hydro Press Release, April 16 12:35 EDT), including similar winds as were reported in the Ottawa area, gusting to 74 km/h and 69 km/h on April 15 and 16, with higher winds reported near the Lake Ontario shoreline, e.g., City Centre Airport reported a maximum gust of 100 km/h on April 15. At least a dozen more local electrical distribution utilities also suffered impacts in southern and eastern Ontario. This provides a basis for better anticipating impacts to Hydro Ottawa's system by monitoring the nature, rate of progression and severity of impacts to up-stream utilities.

The best estimates of total ice accretion indicate total ice accumulations were likely in the 10-15 mm range. Hydro Ottawa's incident reports (Hydro Ottawa, 2018b) suggest ice accretion formed a roughly 6 mm thick layer of ice on conductors, which corresponds to total ice accretion thickness of about 12 mm. Observational data from Ottawa International Airport, although not reporting freezing rain ice accumulation explicitly, suggest a similar amount. A rainfall total of 11.4 mm from April 15 likely represents a total ice accretion amount of approximately 11 mm, since temperatures remained below freezing and observations indicate no liquid precipitation on this date. Between midnight and 10 AM EDT on April 16, another 6 hours of freezing rain was observed. This was followed by a change to temperatures above freezing, with a report of an air temperature of 0.2°C and liquid rain at 10 AM EDT, signaling an end to ice accretion conditions. The majority of electrical outages, seen as an order of magnitude increase in the total number of customers being affected, were triggered by these final few hours of ice accretion, in combination with high winds, in the early to mid-morning of April 16. It is likely that the morning ice accretion only represented a few additional millimeters of ice, since the total precipitation of 23.2 mm

reported for April 16 includes both 6 hours of freezing rain, 1 hour of snowfall, and 12 hours of liquid rainfall.

A review of high impact historical freezing rain events, listed in Klaassen et al. (2003), found a total of 3 other freezing rain storms of similar or greater intensity impacting the Ottawa region since 1940; March 15-16, 1943, December 24-25, 1986, and of course January 4-9, 1998. In contrast to the April 2018 event, all of these cases featured much higher ice accretion totals in the Ottawa area. The events in 1943 and 1998 were far more significant, with ice accretion maxima of ~50 mm and up to 80 mm (slightly less in the City of Ottawa proper), respectively.

The main impacts from the storm were due to tree and branch contacts on lines, emphasising the importance of tree clearing programs. However, a total of 33 utility poles were broken as well. It is notable that poles did not fail at the ground line in most cases but rather a few meters above the ground line. This may be due to significant lateral loading from wind action on ice covered lines, particularly on trunk lines carrying multiple circuits. With increasing lateral loading near the top of the pole, the highest fiber stress within the utility pole begins to shift above the ground line (e.g. Vaughan and Eng, 2008). This results in peak wood fiber stresses occurring in a more tapered portion of the pole with a smaller cross-sectional area, potentially resulting in premature failure. However, we also note that Hydro Ottawa's post storm investigation (Hydro Ottawa, 2018b) indicated that many of the poles were also aged and potentially degraded, including visible rot in some of the broken sections.

Because predicting and even characterising combined loads from wind and ice are challenging, efforts have been made in other jurisdictions to estimate or otherwise categorise potential ice storm impacts from various combinations of wind and ice loads. However, the Sperry-Piltz Ice Accumulation (SPIA) Index (e.g. McManus et al., 2008; SPIA Index, 2009), a combined ice and wind load impacts scale which is becoming popular among meteorologists, may require further tailoring to be applicable to ice storm events in eastern Canada. The index is a 6-point scale, with ranks ranging from 0-5, which provides several wind-ice combinations for each tier which are expected to result in gradually increasing severity of impact. However, for a best estimate of 12 mm of ice accretion and peak winds of 74 km/h, the index indicates the April 15-16, 2018 event would have ranked as a "4" on SPIA Index scale, corresponding to "Prolonged and widespread utility interruptions, extensive damage to main distribution feeder lines, and some high voltage transmission, **5-10 day outage**" [emphasis added]. These impacts are much more severe than what was observed during the April 2019 event and the discrepancy is likely due to the scale's development in the central United States, originating from the Tulsa, Oklahoma National Weather Service office, and therefore corresponds to infrastructure designed to lower ice and wind combination thresholds. However, impacts in Ottawa from the April 2018 do appear to better correlate with an SPIA Index value of "3", "Numerous utility interruptions with some damage to main feeder lines and equipment expected. Tree limb damage is excessive. Outages lasting 1-3 days". This suggests that a tailored version for eastern Canada could be developed with modifications allowing for consideration of more robust design requirements and other local conditions. Such an index is indeed needed, since winds required to significantly exacerbate ice loading can be well below ECCC weather warning criteria for high winds (i.e., gusts to 90 km/h or sustained winds of 70 km/h) and still contribute to impacts. In other words, winds

which are capable of triggering damage to overhead systems, when combined with ice loading, may not trigger a wind warning.

May 4, 2018 Wind Storm

An intense low-pressure system tracked across a large portion of southern and central Ontario through to southern Quebec, as well adjacent areas of the United States south of the Great Lakes. The storm resulted in power outages for approximately 45,000 Hydro Ottawa customers. Wind gusts approaching or exceeding 120 km/h were recorded at several locations, including Kitchener-Waterloo Region International Airport (122 km/h), Hamilton's John C. Munro Airport (126 km/h) and Toronto's Pearson International Airport (119 km/h). Widespread wind damage was reported in all of these regions, including three fatalities attributed to the storm, as well as widespread damage consisting of large branches and/or entire trees snapped or uprooted, shingles and portions of roofs removed from homes and commercial buildings, as well as hundreds of thousands of electrical distribution customers in multiple jurisdictions losing power.

Damage reports, mainly consisting of large branches and individual trees being uprooted, began in states along the international border, stretching in a swath from eastern Michigan and northwestern Ohio, northeast through to the Vermont/Maine border. Damage in eastern Michigan, just north of the City of Detroit and approximately 25 km west of the Ontario border, was first reported at 1:09 PM EDT (SPC, 2018). In the following hours, significant impacts began across southern Ontario's major metropolitan centers of Kitchener-Waterloo and the Greater Toronto-Hamilton Area (GTHA) beginning after 3 pm EDT and continued well into the evening.

High winds occurred in two distinct "waves" which were associated with different portions of the weather system (**Figure B - 1**). This phenomenon was first noted in the GTHA (Weatherlogics, 2018) and was again seen in the Ottawa region several hours later. These winds also impacted two different areas within Hydro Ottawa's service area, with additional evidence that the two periods of high winds also differed in severity and extent. 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. However, many of these customers were very quickly restored, with approximately half of affected customers reported back online by 8:09 PM. This first wave of high winds continued east-northeast, triggering similar outages in the Finlay Creek area, southeast of the more heavily populated portions of the City of Ottawa, by 8:50 PM.

The second period of high winds, which also appeared to be more severe than the first, began in in the late evening, with most damage occurring roughly between 10:00 and 11:30 PM EDT. By 11:40 PM EDT, Hydro Ottawa reported that in excess of 30,000 customers had lost power. In contrast to rapid restoration times for customers in the Kanata and surrounding areas from the first period of high winds, where many customers were restored within approximately one hour, the worst affected areas in the City of Ottawa following the late evening second period of high winds required more than a day to fully restore power.

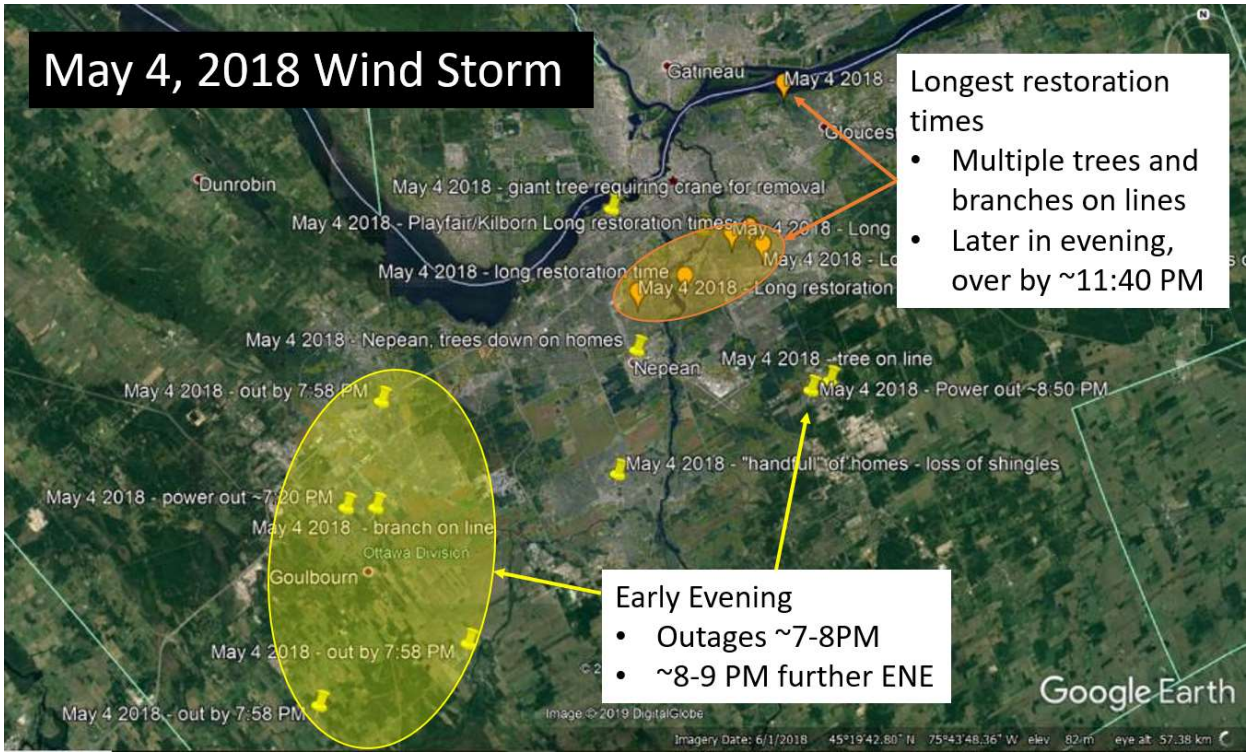


Figure B - 1. Map of damage and outage locations indicating timing and progression of events. Early evening outages SW of the City are circled in yellow, while late evening and long lasting outages are shown in orange.

May 4, 2018 Event – Analytical Results

With such a large-scale wind event, and as with the April 2018 freezing rain storm described above, the potential existed for monitoring incoming impacts and weather conditions for Hydro Ottawa's electrical system by monitoring upstream utilities and meteorological data. In addition to high winds reported at various airports across southern Ontario, approximately 35,000 local electrical distribution customers were reported affected at the height of the storm in the Kitchener-Waterloo region, Toronto Hydro reported over 68,000 customers affected (Toronto Hydro Press Release, May 15, 2018), and Hydro One's rural distribution service reported more than 540,000 customers affected (Hydro One Press Release, May 6, 2018). Hydro One also reported that more than 480 poles were destroyed by the storm, "The damage to our system is so extensive that in some areas we are essentially rebuilding the system." Greg Kiraly, Chief Operating Officer, Hydro One (Hydro One Press Release, May 6, 2018).

In the GTHA, this first period of high winds was associated with thunderstorm activity (Weatherlogics 2018); however, a review of weather radar data and observations at Ottawa's International Airport indicate that thunderstorms were *not* present when the first wave of high winds affected Hydro Ottawa's infrastructure. The lack of thunderstorm activity, which acts to enhance wind gusts, may have been a factor in the less severe damage and lower winds associated with the first period of high winds in the Ottawa area.

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 (**Figure B - 2**). The highest winds reported at Ottawa International were gusts to 96 km/h which occurred during the second period of high winds in

the late evening. However, a few locations reported impacts such as the removal of cladding and large sections of roof shingles from homes, as well as multiple large trees being either completely uprooted or being snapped off at the trunk. These types of impacts are usually associated with winds in excess of 105 km/h (ECCC, 2014). Furthermore, a portion of south Ottawa, stretching from the Carlton Heights neighbourhood east-northeast to Alta Vista, were subject to the longest restoration times (> 24 hours), reportedly due to *multiple* trees and branches on lines. Damage to multiple large branches and trees, as opposed to reports of isolated trees and branches, is indicative of winds likely in excess of 100 km/h. This result indicates the need for better monitoring of important climate parameters, since even for large scale storms affecting multiple provinces and states, measurements taken at a single point may not be fully representative of conditions responsible for the most severe impacts.

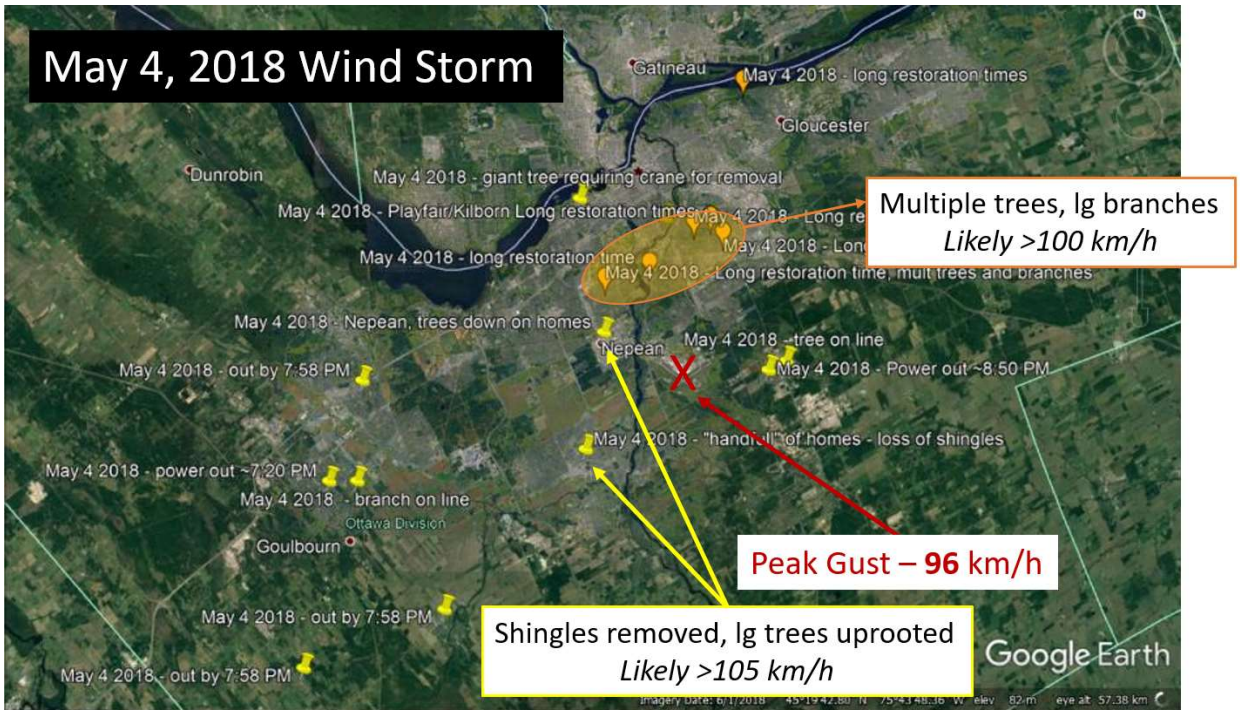


Figure B - 2. Map comparing peak gust value measured at Ottawa International Airport with areas reporting damage suggesting higher wind speed values.

Finally, we address the mechanisms responsible for producing high winds. These findings may explain the differences in damage severity and could also assist with future anticipation of and response to similar events. The first period of high winds was associated with a portion of the weather system called a “low-level jet”, a stream of high-speed air present in low-pressure systems located approximately 1.5 km above the surface ahead of the surface cold front. The momentum from this stream of fast-moving air can be transported to the surface though a number of mechanisms, including embedded thunderstorm or rainfall activity, with the falling precipitation acting to “carry” momentum from winds aloft down to the surface. Winds within the low-level jet were around 120 km/h, which correspond very well with maximum wind gusts reported in the GTHA and Kitchener-Waterloo area in the early afternoon in association with thunderstorm activity (Weatherlogics, 2018). However, no thunderstorm activity was present in Ottawa when this portion of the weather system reached the area, meaning elevated streams of high winds were less directly able to affect the surface. However, the second period of high winds, which occurred in colder

air behind the cold front and located just south of the center of the low pressure system, were far more intense and damaging. Given the location and intensity of these winds, they were possibly associated with a phenomenon referred to as a "sting-jet" (e.g. Browning 2004). This is a separate stream of high winds that requires specific conditions to form and result in a swath of extremely high winds generally located to the immediate south of the track of the center of low pressure. These events occur more frequently in areas prone to more intense low pressure systems such as northern Europe, and can produce wind gusts in excess of 200 km/h in severe cases.

September 21, 2018 Tornado Outbreak

The September 21, 2018 tornado outbreak consisted of at least 7 separate tornadoes (Sills et al. 2018), from as far south as Sharbot Lake, Ontario, to as far north as the Baskatong Reservoir in western Quebec, approximately 140 kilometers north of Ottawa. Public weather forecasts for the day indicated the potential for severe thunderstorms and high winds, but the potential for significant (EF2 or stronger) tornadoes was not discussed. Severe winds associated with the strong low-pressure system began to trigger power outages before the tornadoes formed, with Hydro Ottawa reporting "multiple outages" across their network by 3:56 PM EDT via Twitter. Given the vague nature of forecast and warnings and the lack of a tornado watch being in place, this wind damage may have confused response crews into assuming the "main event" had already begun.

Hydro Ottawa's service area was impacted by the two strongest confirmed tornadoes within the outbreak, the long-tracked Kinburn-Dunrobin-Gatineau tornado, rated EF3 with estimated winds of up to 265 km/h, and the Nepean-South Ottawa tornado, rated EF2 with maximum estimated winds of around 220 km/h. The Kinburn-Dunrobin-Gatineau tornado first formed near Kinburn at approximately 4:32 PM EDT. It was already the second tornado of the day, produced by a storm cell that had just impacted the Calabogie area. Tornadoes on this day were also characterised by extremely rapid forward motion. The Kinburn-Dunrobin-Gatineau tornado crossed the Ottawa River at approximately 4:52 PM EDT, having travelled nearly 30 km in 20 minutes. It produced damage of up to EF3 intensity both in Dunrobin and later in Gatineau, Quebec, and reached a maximum width of over 1.3 km in the Dunrobin area.

Approximately one hour after the Kinburn-Dunrobin-Gatineau tornado crossed the Ottawa River, at 5:51 PM EDT, the Nepean-South Ottawa tornado formed in association with a second line of storms approaching Ottawa from the west. The tornado produced minor damage to homes in the eastern portions of the Glen Cairn neighbourhood of Kanata before tracking to the northeast, rapidly widening and intensifying. The most severe damage occurred in the Arlington Woods and Craig Henry neighbourhoods of Nepean, reaching a maximum intensity of EF2 and a maximum path width of over 750 meters. After exiting the Craig Henry neighbourhood, the tornado weakened and narrows but remained on the ground for several more minutes, impacting the Merivale Transmission station at almost exactly 6:00 PM EDT, as well as downing medium voltage trunk lines after crossing the Rideau River. The tornado dissipated shortly after at approximately 6:09 PM EDT, immediately south of the Ramsayville industrial park.

September 21, 2018 Event – Analytical Results

Although other multi-tornado events have affected the Ottawa River Valley and surrounding areas in the past (**Figure B - 3**), this appears to be the first event in recent history – and since higher quality tornado records have been kept – in that two significant (i.e. EF2 or stronger) tornadoes affected Hydro Ottawa's service area on the same day. The two tornadoes affected the Hydro Ottawa service area for a total of approximately 38 minutes, meaning that the vast majority of the damage that resulted in over 207 thousand customers occurred in less than ¾ of an hour.

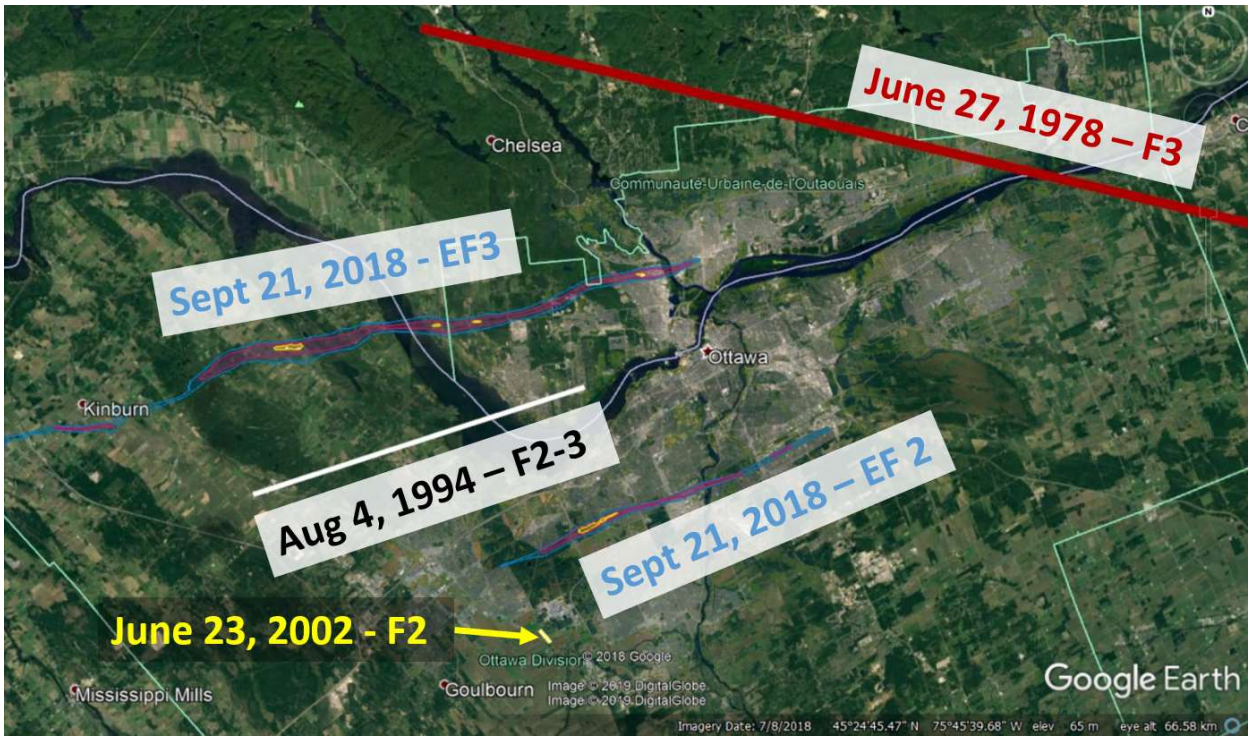


Figure B - 3. Map of all confirmed significant (F2+/EF2+) tornadoes in the Ottawa area for the period 1970 to 2018. Detailed track maps for the Sept 21, 2019 event courtesy of Sills et al. (2018), track data for historical events from Sills et al. (2012).

One of the key concerns expressed by Hydro Ottawa staff were that the gravity of the situation, and the potential for strong tornadoes, was not clear from readily available severe weather watch and warning statements. On August 1, 2018, only seven weeks prior to this event, another series of storms affected the City of Ottawa and surrounding area, triggering tornado warnings. However, no damage was reported, and the event resulted in a false alarm. This led to a reduced level of concern from staff when tornado warnings were issued again on September 21. Outreach and additional severe weather education may have assisted in better interpretation of warning messages, since only a portion of tornado warnings result in confirmed tornado activity. Access to additional weather information and messaging could have assisted in better framing events on the two different days, since the risk and potential impacts from tornadoes were much greater on September 21 than on August 1. This difference was reflected in discussions from several meteorologists active on social media during the September 21 event, information which did not reach Hydro Ottawa response crews.

Damage surveys conducted by joint teams from Environment and Climate Change Canada (ECCC) and the University of Western Ontario (UWO) wind engineering group were shared with the assessment team (Sills et al., 2018). These helped better clarify what occurred at various points along the damage tracks, including impacts to Merivale TS, critical medium voltage trunk lines, and the Arlington Woods and Craig Henry neighbourhoods. Maps of tornado damage tracks indicated that Merivale TS suffered a direct strike from the Nepean tornado, and that the tornado was likely at EF1 intensity when impacts occurred, suggesting maximum winds of up 170 km/h, but of lesser intensity than large portions of the first part of the tornado track, and certainly of much lesser intensity than what was experienced in portions of the Dunrobin-Gatineau EF3 tornado damage area. Similarly, a maximum intensity of EF1 damage was also indicated along many of the trunk lines carrying multiple circuits. Finally, the severe overhead system damage in south Nepean, which was characterised by severe damage to individual customer connections to the system and resulting in extended restoration times, was associated with EF2 damage to homes and trees, suggesting winds in the 180 to 220 km/h range. When events of such intensity occur, all overhead systems within the area of most extreme winds are damaged or destroyed, significantly increasing restoration times due to the need for repairing and replacing each individual customer connection.

Forensic Case Study Based Recommendations

Detailed recommendations stemming from the case studies are provided below, including a description of recommended actions and associated reasoning.

Operations, Maintenance and Monitoring

Use of social media to enhance situational awareness before and during severe weather events:

Social media, which is currently being used very effectively by Hydro Ottawa to communicate and interact with customers, can also be used to keep Hydro Ottawa informed of the potential development of severe weather events. Many of Canada's most highly skilled meteorologists are also active on social media – particularly Twitter – and their accounts can be monitored to help refine understanding of both the potential hazard or hazards for a given day, as well as provide more clarity and detail during an event. Specific applications include:

- Monitoring of Twitter accounts from meteorologists responsible for forecasting in Canada, Ontario and Quebec:
    - Suggested Twitter accounts include: Dr. David Sills (@dave_sills), Executive Director, Northern Tornadoes Project, University of Western Ontario; Mark Robinson (@StormhunterTWN), Jaclyn Whittal (@jwhittalTWN) and Brad Rousseau (@bradrousseau), meteorologists and storm chasers at The Weather Network; Antoine Petit (@MeteoAntoine), Monica Vaswani (@monhyp88) and Robert Kuhn (@KuhnyRob), meteorologists/weather forecasters at Environment and Climate Change Canada, responsible for forecasting in Ontario and southern Quebec.
- Monitoring of Twitter accounts from upstream utilities: Depending on the scale of the severe weather event, important information can be gleaned from monitoring weather impacts reported by utilities in geographical regions affected by weather systems prior to Hydro Ottawa

being affected (e.g., the May 4, 2018 wind storm produced impacts in the Kitchener-Waterloo and Greater Toronto Areas several hours before affecting the City of Ottawa). Representative locations will depend on the conditions of the day of the event, since weather systems

Additional monitoring of key meteorological parameters within Hydro Ottawa's service area:

Many of the weather and climate parameters that are important for impacts to utilities are not well monitored and/or data is not immediately available in real-time. In particular, gaps are noted in recording of:

- Freezing precipitation ice accretion thickness; and,
- Wind speeds, both sustained and gusts.

Additional data on these key parameters would provide more representative for comparison to resulting infrastructure damages, as well as real-time monitoring for operations and response activities, including the potential for developing tailored, real-time warning systems specific to Hydro Ottawa's network. Long term monitoring will also provide better information regarding any differences in climate conditions throughout the service area, addressing questions such as if wind loads are indeed less significant for areas outside of Ottawa's core (e.g., Casselman). New monitoring sites should be distributed throughout the service area and would also require installation of data archiving and storage systems.

Monitoring weather conditions and electrical distribution and transmission outages for locations "up-stream" of Hydro Ottawa's service area:

For larger scale weather systems typical of late-fall, winter and early to mid-spring, meteorological conditions such as wind gust speeds and precipitation amounts, as well as reports of associated impacts such as power outages and/or tree and structural damage, could be monitored to help anticipate impacts upwards of several hours in advance of Hydro Ottawa's service area suffering impacts. These can also provide some indication of the expected nature and severity of approaching severe weather, which can be taken into account for operational and response measures. Determination of representative "up-stream" locations and conditions depend on conditions on the day of the event, but typically weather events approach from the west. However, interpretation of available information would be significantly improved when combined with additional weather awareness and forecast training for staff.

Key "up-stream" utilities identified in the forensic case studies include Hydro One (particularly its rural distribution network), Toronto Hydro, Alectra Utilities (now servicing large portion of the GTHA), as well as multiple smaller utility companies.

Planning and Training

Basic severe weather forecasting and awareness training for staff:

A multitude of weather forecasting and monitoring products are readily available but require additional education and training for proper interpretation and use. These include weather radar – particularly useful during severe thunderstorm events such as tornado and large hail events – satellite imagery, lightning network observations, as well as a multitude numerical weather forecast products. Hydro Ottawa staff could make use of these tools if provided with sufficient training. With such training, staff would be much better able to interpret available weather information, including understanding the meaning and importance of weather watches and warning, and possibly being able to target particular locations within the service area which may have suffered impacts during an event (e.g. tracking specific storm cells to understand possible tornado track locations in real-time). Training could include so-called "weather map typing", which uses weather patterns identified in past severe weather events to help forecast weather event types and severity. Such weather maps are already available for ice storm events and could assist with anticipating particularly severe events and impacts.

System Management, Repair and Upgrades

Review of/increased emphasis on tree trimming operations:

The majority of damage to overhead systems result from tree contacts. More aggressive tree trimming practices, or greater operational investment in tree trimming and maintenance, can significantly reduce the number of outage events resulting from conditions that otherwise would not be capable of causing direct damage to the infrastructure itself. This has been successfully implemented by Toronto Hydro following their PIEVC risk assessment (R. McKeown, pers. comm.).

Improved outage reporting systems:

To best correlate impacts to electrical infrastructure with weather observations, an automated outage reporting system which indicates the exact time and location (as close as possible) that outages are triggered, as well as which components failed and the number of customers affected, would be of considerable assistance to both operations and response, as well as post-event investigations. Automated digital recording and archiving of failures would assist in more quickly locating outages, as well as in prioritising outages when multiple outages occur in rapid succession.

Strategic equipment upgrades:

As systems age and regular upgrades are executed, or when structural failures occur and broken components require immediate replacement, individual components can be replaced with more robust or resilient components. For example, this can include replacing broken poles with higher class poles, particularly for infrastructure in locations which have demonstrated or have been assessed to have greater vulnerability. Strategic upgrades can significantly increase system resilience, particularly if done in a sustained, targeted, and prioritised fashion.

Break-away connectors and other sacrificial components:

Break-away and other controlled failure components speed up restoration times and reduce or prevent damage to adjacent components in the event of a failure. This is particularly true of severe weather events in which damage to individual customer grid connections occur, as was observed in the more intense areas of residential damage during the September 21st tornadoes, and was reported in the 1998 ice storm.

Improved disaster response, including operations and training, for extreme events:

For particularly severe events, such as the January 1998 ice storm and September 2018 tornadoes, the cost of designing infrastructure to *prevent* failures is prohibitive. Hence, long-duration power outages and severe damage to portions of the distribution system are expected during these events, and response to these particularly severe cases requires disaster response rather than structural hardening or other adaptations. Improved disaster response includes incorporating lessons learned from historical events, as well as improved situational awareness and staff training. This includes the execution of realistic disaster scenario excercises, to understand what types of disasters are possible, how likely they are to occur, and most importantly to know when they are occurring (e.g., what conditions and signs are available to differentiate a severe thunderstorm event that occurs every few years versus a day which could result in large, intense tornadoes affecting the service area). Pre-planning and pre-defining strategies can be critical to reducing impacts and improving response times during major events.

Event Specific Recommendations

April 15-16 Ice and Wind Event:

- Develop locally relevant/tailored version of SPIA Index to allow for better characterisation of potential impacts and expected recovery times for combined wind and ice loading events;
- Review medium voltage trunk corridors to identify any other locations which may be lacking in storm guys or other key structural components leading to greater vulnerability.

Appendix C: Detailed Discussion of Analytical Results

Temperature – Extreme Heat

Thresholds:

T_{max} ≥ 25°C; 30°C; 35°C; 40°C

T_{mean} ≥ 30°C

Extreme heat was evaluated by calculating the number of days per year with the respective temperature parameter exceeding the selected threshold. Historical baselines of extreme heat climate parameters were established using data from the Ottawa Airport meteorological station and projections were generated using CMIP5 ensemble projections and the Delta Approach.

All extreme heat parameters are projected to increase in frequency under climate change. Increased frequencies of the number of days per year with T_{max} ≥ 25°C and T_{max} ≥ 30°C have been observed during the 1981-2010 baseline, with continued notable increases in frequency by the 2050s: Baseline mean of ~62-63 time per year increasing to ~99 times per year in the 2050s for T_{max} ≥ 25°C and baseline mean of ~14-15 times per year increasing to ~42 times per year in the 2050s for T_{max} ≥ 30°C (**Figure C - 1** and **Figure C - 2**, respectively). During the 1981-2010 time period, T_{max} ≥ 35°C is observed 0-3 times per year, with an annual probability of 50%, and is projected to increase to ~6 time per year in the 2050s (**Figure C - 3**). Historically, T_{max} ≥ 40°C and T_{mean} ≥ 30°C have not be observed at the Ottawa Airport, however, under climate change it is expected to see these temperature thresholds exceeded ~1-2 times per year and ~4 times per year, respectively, during the 2050s.

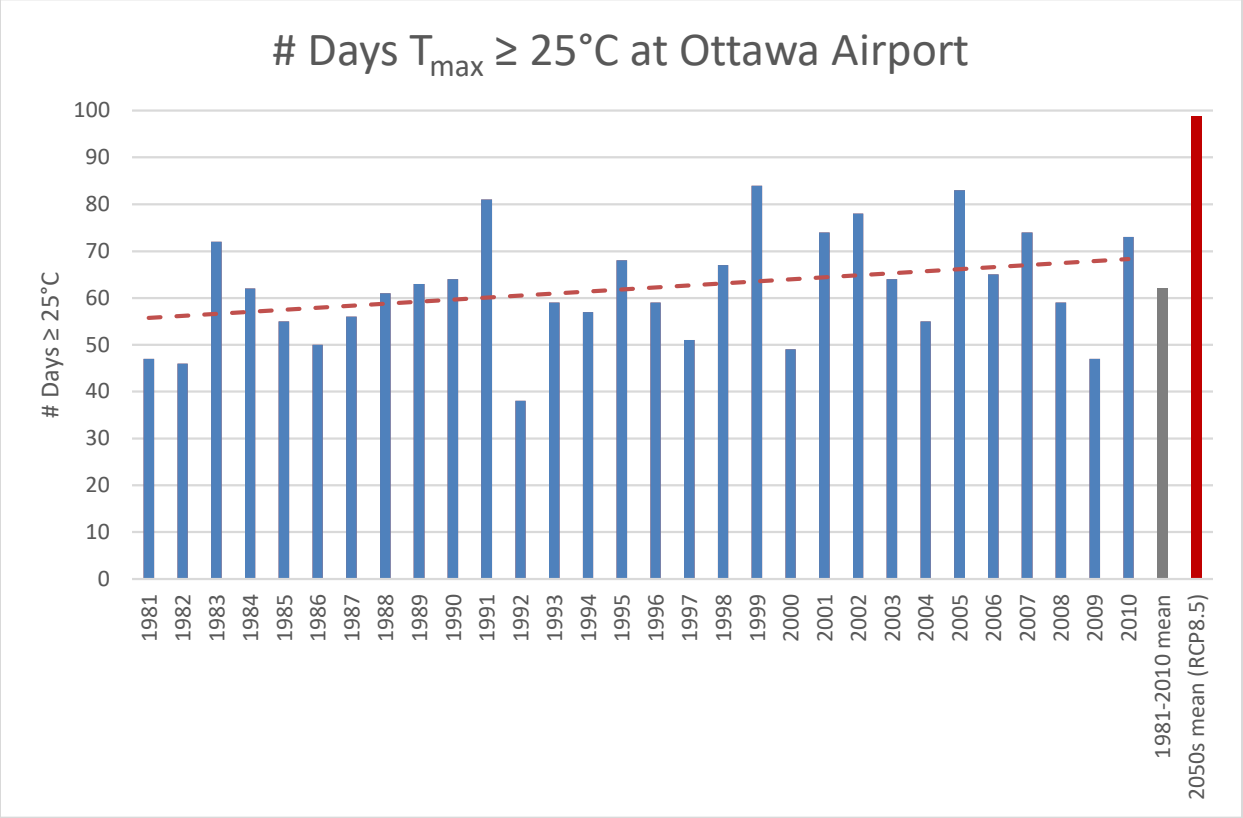


Figure C - 1. Number of days per year with the maximum temperature ≥ 25°C during the 1981-2010 time period at Ottawa Airport. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

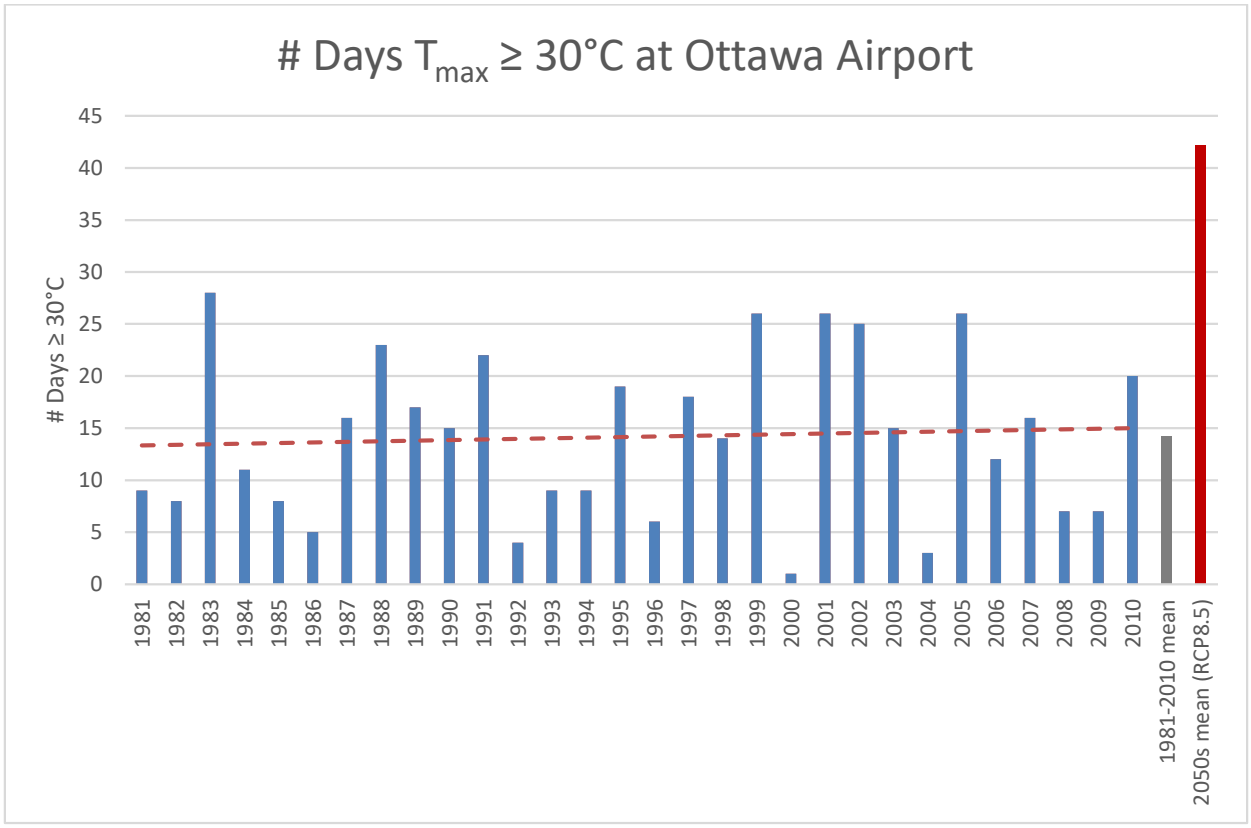


Figure C - 2. Number of days per year with the maximum temperature ≥ 30°C during the 1981-2010 time period at Ottawa Airport. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

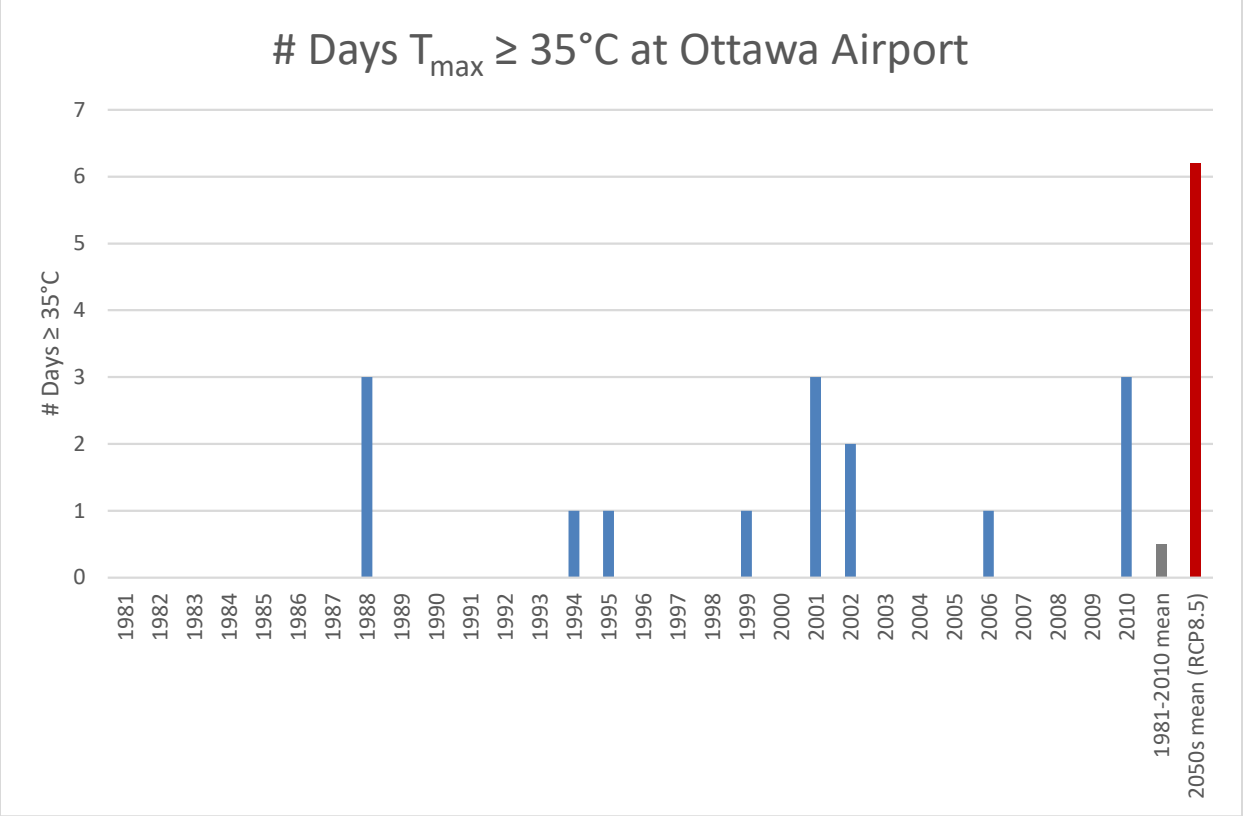


Figure C - 3. Number of days per year with the maximum temperature ≥ 35°C during the 1981-2010 time period at Ottawa Airport. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

Heat Waves

Thresholds:

Consecutive Days with $T_{max} \geq 30°C$ and $T_{min} \geq 23°C$;

Consecutive Days with $T_{max} \geq 30°C$ and $T_{min} \geq 25°C$

Heat waves were evaluated by calculating the number of events per year corresponding to the selected threshold. Historical baselines for the frequency of heat waves were established using data from the Ottawa Airport meteorological station and projections were generated using CMIP5 ensemble projections and the Delta Approach.

The frequency of heat waves is projected to increase under climate change. During the 1981-2010 time period, the Greater Ottawa Region has experienced two heat waves of consecutive days with $T_{max} \geq 30°C$ and $T_{min} \geq 23°C$, with the heat waves lasting 2 days, resulting in an annual probability of 7%. Under climate change, these $T_{max} \geq 30°C$ and $T_{min} \geq 23°C$ heat waves are projected to increase in frequency, averaging ~2 heat waves per year, and length (average length of 2.4 days and an average maximum length of 5 days) during the 2050s under the RCP8.5 scenario. During the 1981-2010 time period, the Greater Ottawa Region has not experienced a heat wave of consecutive days with $T_{max} \geq 30°C$ and $T_{min} \geq 25°C$. Under climate change, however, these $T_{max} \geq 30°C$ and $T_{min} \geq 25°C$ heat waves are projected to occur with an annual probability of 37% (and a 30-yr probability of >99%) and with an average length of 2.5 days (and average maximum length of 4 days) during the 2050s under the RCP8.5 scenario.

Temperature – Extreme Cold

Threshold:
$T_{min} \leq -35°C$

Extreme cold was evaluated by calculating the number of days per year with the minimum temperature exceeding the selected threshold. The historical baseline was established using data from the Ottawa Airport meteorological station and the 2050s projection was generated using CMIP5 ensemble projections and the Delta Approach.

Extreme cold events with $T_{min} \leq -35°C$ at the Ottawa Airport are historically rare (3% annual probability), with a minimum temperature of -35°C or below being observed only one day during the 1981-2010 baseline period (in 1981). Under climate change, the frequency of extreme cold events is projected to further decrease, with a 0.1% annual probability projected for the 2050s under the RCP8.5 scenario.

Nevertheless, while the number of days with $T_{min} \leq -35°C$ is projected to be rare under climate change, the occurrence of extreme cold events is not expected to vanish completely. The amplified warming in the Arctic under climate change has been linked to a more unstable Polar Vortex and the occurrence of extreme weather in the mid-latitudes (30 – 60°N) (Francis and Vavrus, 2012; Coghlan, 2014; Kretschmer et al., 2018). Subsequent wintertime southward dips in the Polar Vortex over Southern Ontario have the potential to result in extreme cold events such as those in recent winters (2012-13, 2013-14, 2017-18, and 2018-19) and could impact the Greater Ottawa Region. Furthermore, the effects of Polar Vortex events under climate change (Mitchell et al., 2012) are not well captured by climate models, meaning that the future frequency of extreme cold events may be somewhat underestimated.

Rain

Threshold:
50 mm of rainfall in 1 hour

Short duration-high intensity (SDHI) rainfall was evaluated using Intensity-Duration-Frequency (IDF) rainfall data and calculating the probability of occurrence of a rainfall of 50 mm in 1 hour. Historical IDF station data is available from the Ottawa Airport meteorological station (1967-2007, not inclusive of all years with data missing for 2001 and 2005). 2050s projections were generated using specialised literature and expert climatological interpretation.

Currently, the occurrence of SDHI rainfalls of 50 mm in 1 hour is rare, with an annual probability of 1% during the 1981-2010 baseline. While the frequency of these events is projected to increase under climate change, rainfalls of these magnitude will continue to be rare, with an annual probability of 4.5% during the 2050s under the RCP8.5 scenario. Nevertheless, a notable increase in the 30-year probability from 25% during the baseline to 75% during the 2050s is projected.

The projected general trends of increasing rainfall are expected to be expressed in higher rainfall rates for individual events. SDHI rainfall (e.g. convective thunderstorm rainfall) has been shown to be particularly sensitive to increases in air temperature and atmospheric moisture, increasing at a rate proportional to the Clausius-Clapeyron (CC) rate. This CC relation (based on atmospheric thermodynamics) is founded on an empirical relationship between air temperature and the amount of water the air could potentially hold, increasing as air temperature also increases. Therefore, warmer air temperatures have the potential to provide increasingly greater amounts of moisture, producing more intense extreme rainfall events as a

consequence. Accordingly, low to moderate increases in rainfall amounts are expected with individual events, while very large increases in rainfall rates may occur with the most extreme storms resulting in increased frequency of SDHI events, such as 50 mm rainfalls in 1 hour.

Freezing Rain & Ice Storms

Thresholds:
Ice accumulation of
25 mm; 40 mm

Freezing rain and ice storms were evaluated by calculating the number of events per year where ice accumulation exceeded the selected threshold. Historical baselines were established using historical incident data in Klaassen et al. (2003), as well as ice accretion design data provided in the CSA design standard for overhead electrical transmission systems (CSA, 2010). This specialised data set and design criteria were used instead of climate station data because ice accretion information is not regularly reported at climate stations. Theses data sources were further supplemented by media reports for the most recent (April 2018) high impact ice storm in the Greater Ottawa Region. Projections were generated through literature review and expert climatological interpretation. Cheng et al. (2011) produced downscaled estimates of future ice storm activity, including a breakdown of monthly and seasonal changes, which were used here to estimate future activity in the Greater Ottawa Region.

Several high impact ice storms have affected the Greater Ottawa Region, with the first major ice storm affecting the Ottawa River Valley listed by Klaassen et al. (2003) as having occurred in November of 1909, although earlier less well documented events may have occurred. Historical research was able to confirm four major events, i.e., those which resulted in long term and widespread power and communication outages, affecting the region since 1940, including the most recent April 2018 event as well as the infamous January 1998 ice storm. As such, larger magnitude freezing rain and ice storm events of 25 mm and 40 mm of ice accumulation are relatively rare, with annual probabilities of 5% and 2.5% observed during the 1981-2010 baseline, respectively. While the frequency of these events is projected to increase under climate change, these large magnitude events will continue to be relatively rare, with annual probabilities of 6% (ice accumulation ≥ 25 mm) and 3.8% (ice accumulation ≥ 40 mm) during the 2050s under the RCP8.5 scenario. Nevertheless, the 30-year probabilities of an event with 25 mm ice accumulation is notable, with a baseline 30-year probability of 79% and projected to increase to 84% in the 2050s. Similarly, for an event with 40 mm ice accumulation, the 30-yr probability is projected to increase from >50% during the baseline to ~70% during the 2050s.

Furthermore Cheng et al. (2011) note that while future warming may result in a slight decrease of 10% or less in shoulder season ice storm activity (i.e., November and April), a consistent and significant increase in freezing precipitation was indicated for the cooler period, particularly in January which may see future changes of 75% to 80%, or nearly doubling the occurrence of mid-winter ice storm events.

Snow

Thresholds:
Snow accumulation
≥ 5 cm; 10 cm; 30 cm

Snow was evaluated by calculating the number of events per year exceeding the selected threshold. Historical baselines were established using data from the Ottawa Airport meteorological station. Projections were generated using literature review, climate analogues, and expert climatological interpretation.

The number of snow events per year is projected to remain roughly steady for all three magnitude snow events – snow accumulations ≥ 5 cm, ≥ 10 cm, and ≥ 30 cm. While the total amount of snowfall in a given season is projected to decrease under climate change, it is likely that the frequency of moderate to heavy snowfall events will remain nearly constant. It may seem counter-intuitive to expect steady trends in the frequency of moderate to heavy snowstorms during warming winters, however, meteorological principles dictate that warmer temperatures allow for more moisture to be contained within an air mass, and that if the mean temperature remains below freezing, this precipitation would continue to fall as a frozen precipitation type such as snow, freezing rain, or sleet. The Greater Ottawa Region also has the particular climatological condition of being subject to the western edge of deepening Atlantic storms and is also situated in a valley where colder temperatures predominate for longer periods of time. Larger snowfall events still will remain likely in warmer climate scenarios, even with a decreasing total overall snowfall for a season, as extreme cold outbreaks (so-called “Polar Vortex” winters) are likely to continue occurring in response to arctic amplification (Zhang et al., 2016; Overland, 2016) and stuck weather patterns. Furthermore, studies in parts of the United States have indicated that severe snowstorms (i.e. blizzards) do occur in otherwise warmer and shortened winter seasons, as storms require only a brief period of anomalously cold temperatures (along with the right combination of moisture and atmospheric dynamics) to produce them (Lawrimore et al, 2014; Melillo et al., 2014). It is therefore likely that the frequency of moderate to heavy snowfall events will remain constant through the mid-century (i.e. 2050s).

While small increases in the frequency of lower magnitude snow events – snow accumulations ≥ 5 cm and ≥ 10 cm – have been observed during the 1981-2010 baseline, the frequency of these events is projected to remain steady under climate change. Events with snow accumulation ≥ 5 cm is projected to remain steady with ~15 events per year observed during the baseline and projected for the 2050s under the RCP8.5 scenario (**Figure C - 4**). Similarly, the frequency of events with snow accumulation ≥ 10 cm are observed ~5-6 times per year during the baseline and have a projected occurrence of ~5 time per year in the 2050s under the RCP8.5 scenario (**Figure C - 5**).

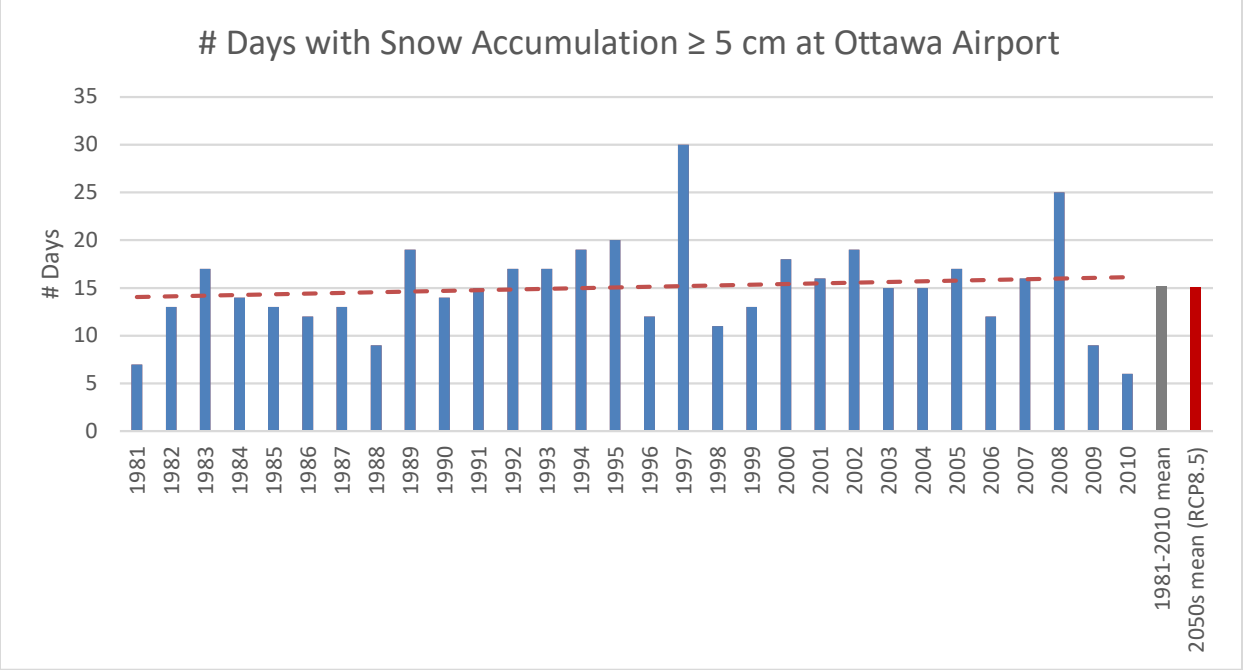


Figure C - 4. Number of events per year with a snowfall accumulation ≥ 5 cm at the Ottawa Airport during the 1981-2010 time period. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

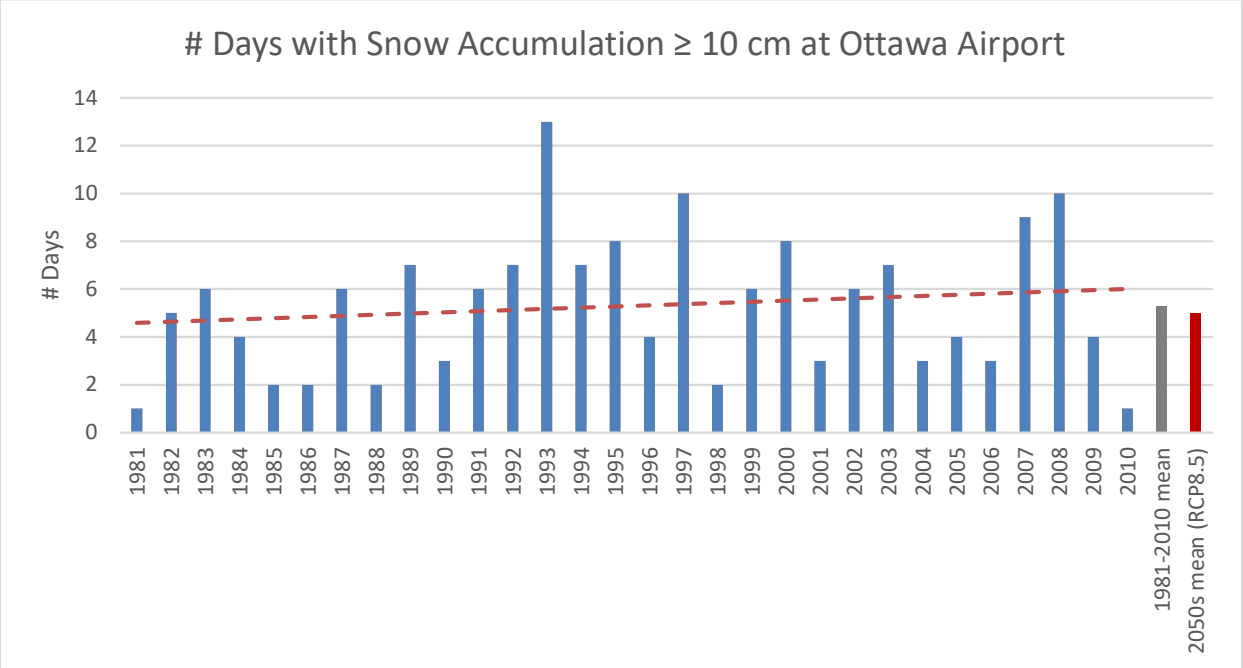


Figure C - 5. Number of events per year with a snowfall accumulation ≥ 10 cm at the Ottawa Airport during the 1981-2010 time period. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

Larger magnitude snow events – snow accumulations ≥ 30 cm – are relatively rare. During the 1981-2010 baseline, events with snow accumulations ≥ 30 cm have been observed 4 times (1984, 1993, 2007, and 2008), with an annual probability of 13%. These larger magnitude events are projected to decrease slightly under climate change, with an annual probability of 10% projected for the 2050s under the RCP8.5

scenario. Nevertheless, the 30-year probabilities of these events are notable, with a 30-year probability of 98% during the baseline and >95% projected during the 2050s.

High Winds

Thresholds:
Wind gusts ≥ 60 km/hr;
80 km/hr; 90 km/hr; 120 km/hr

High winds were evaluated by calculating the number of days per year exceeding the selected threshold. Annual frequency of events exceeding the selected gust thresholds were evaluations. In addition to annual frequency evaluations, easterly wind events with gusts of 60+ km/hr during the warm season (April-Sept.) and summer (June-Aug.) and events with easterly wind events with gusts of 80+ km/hr during the cool season (Oct.-March) and winter (Dec.-Feb.) were evaluated. These lower speed but easterly wind events are of particular interest to Hydro Ottawa as North-South lines are more vulnerable and are guyed on the westside against the prevailing winds. Historical baselines were established using data from the Ottawa Airport meteorological station. Projections were generated using literature review, specialised studies, and climatological interpretation. Currently, the only available downscaled climate change projection studies of damaging wind gusts available for eastern Canada are those produced by Cheng (2014), employing a suite of previous generation (IPCC 4th Assessment Report) climate models. As with other extreme events, specialised studies are needed for such localised and relatively rare extreme events. Cheng (2014) grouped locations into different regions with similar wind gust climates, which also allowed for the comparison of the Greater Ottawa Region's wind climate to other similar stations.

The frequency of events with wind gusts ≥ 60 km/hr is projected to increase slightly under climate change. Annually, the frequency of events with wind gusts ≥ 60 km/hr from any direction is currently ~14-15 times per year during the 1981-2010 baseline and is projected to increase to ~16 time per year in the 2050s under the RCP8.5 scenario. Events with easterly wind gusts ≥ 60 km/hr are less common, with annual probabilities for the baseline of 28.9% during the warm season (April-Sept.) and 2.6% during meteorological summer (June-Aug.). Under climate change the annual probabilities are projected to increase to 32.4% (warm season) and 2.9% (summer) during the 2050s under the RCP8.5 scenario. While the annual probabilities of these easterly wind gust events are lower, the 30-year probabilities are notable, especially for warm season events, with 30-year probabilities of ~100% for warm season events and 55%-60% for summer events (baseline and projected).

The annual frequency of events with wind gusts ≥ 80 km/hr is projected to remain steady under climate change while the cool season and winter frequency of events with easterly wind gusts ≥ 80 km/hr is projected to increase slightly. Annual, the frequency of events with wind gusts ≥ 80 km/hr from any direction is projected to remain steady with ~1-2 times per year observed during the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario. Events with easterly wind gust ≥ 80 km/hr are less common, with annual probabilities for the baseline of 5.3% during the cool season (Oct.-March) and 2.6% during meteorological winter (Dec.-Feb.). Under climate change the annual probabilities are projected to increase to 6.3% (cool season) and 3.2% (winter) during the 2050s under the RCP8.5 scenario. While the annual probabilities of these easterly wind gusts are lower, the 30-year probabilities are still notable,

especially for cool season events, with 30-year probabilities of 80%-85% for cool season events and ~55%-60% for winter events (baseline and projected).

The frequency of higher magnitude wind events – wind gusts ≥ 90 km/hr and ≥ 120 km/hr (any wind direction) – are also projected to increase under climate change. During the 1981-2010 baseline, events with wind gusts ≥ 90 km/hr have an annual probability of 23%, which is projected to increase to 29% in the 2050s under the RCP8.5 scenario. Although events with wind gusts ≥ 90 km/hr are less common, during both the baseline and 2050s time periods, there's a 30-year probability of >99% of this event occurring. Events with wind gusts ≥ 120 km/hr are relatively rare, with an annual probability of 2.5% observed during the 1981-2010 baseline. The frequency of these high magnitude wind events are projected to increase slightly to 3.1% annual probability during the 2050 under the RCP8.5 scenario. During the baseline and 2050s time periods, there's a 30-year probability of an event with wind gusts ≥ 120 km/hr occurring of 53% and 61%, respectively.

Lightning

Threshold:
Strikes near infrastructure (flashes/km^2/year)

Lightning was evaluated using lightning flash density (flashes/km^2). A historical baseline (1998-2018) was established using the Environment and Climate Change Canada (ECCC) Canadian Lightning Detection Network. Projections were generated using literature review, specialised studies, and expert climatological interpretation.

Flash density varies across the Greater Ottawa Region (**Figure C - 6**), differing from approximately 1.0 to 1.2 lightning flashes per square kilometer. A flash density of 1.13 per square kilometer per year was therefore selected as a representative value for assets within the Ottawa urbanised areas. Note that resulting probability values used are based on further analyses which take into account the probability of a strike on a specific individual asset, which resulted in annual probabilities of ~1-1.5% for a specific asset being impacted under current and future climate regimes.

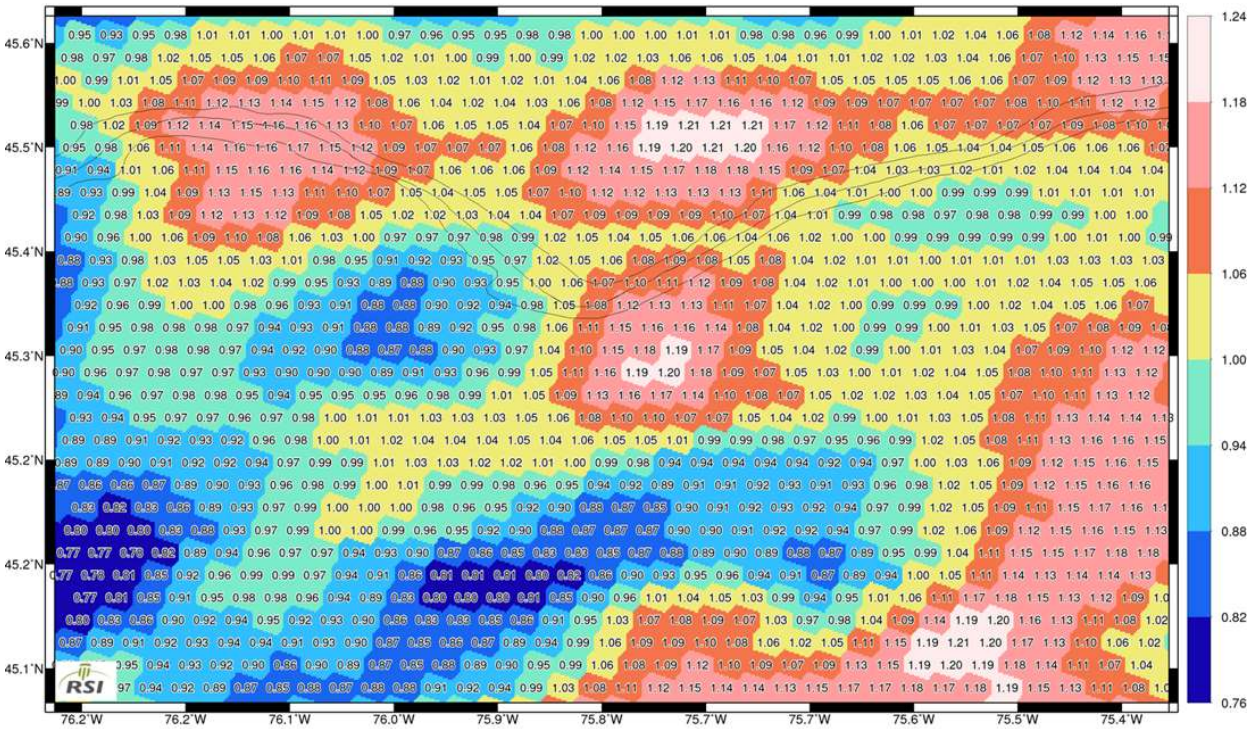


Figure C - 6. Map indicating the lightning flash density in lightning flashes per square kilometre per year for the Greater Ottawa Region and surrounding areas. (Data from the ECCC National Lightning Database; plot produced by Risk Sciences International.)

Climate change studies attempting to quantify future differences in lightning activity have varied by nearly an order of magnitude in projected change values depending on the methodology and associated assumptions used. Greater increases for the North American continent are reported for more robust, meteorological process-based estimates of future lightning activity (e.g. Romps et al., 2014). This is in contrast to global studies which indicate an overall potential *decrease* in the number of lightning strikes on a global scale under a warming climate (Finney et al., 2018), but these changes in global average are mainly driven by decreases in lightning activity in the tropics and are not applicable to mid-latitude countries such as Canada and the United States.

Rough estimates of increases in lightning frequency for the Greater Ottawa Region, based on a study from the U.S. (Romps, 2014), indicated that lightning activity could be expected to increase by about 12 percent per degree Celsius of warming, with about a 50 percent rise over the 21st century. Therefore, it is projected that flash density in the Greater Ottawa Region will increase in annual frequency from 1.1% in the 1998-2018 time period to 1.5% in the 2050s under the RCP8.5 scenario. Furthermore, the length of the higher frequency lightning season is also expected to increase with warming under climate change.

Tornadoes

Thresholds:

EF1+ in Hydro Ottawa service area (City of Ottawa);

EF1+ point probability (i.e. striking a specific asset in the City of Ottawa service area)

Tornadoes were evaluated for the number of F1+ (historical) and EF1+ (since 2013) rated tornadic events per year[1]. A historical baseline was established using the Canadian Tornado Database (1981-2009; Cheng et al., 2013), Ontario historical tornado listing (1892-2009), and media sources (for more recent events). Projections were generated through literature review, specialised studies, and using expert climatological interpretation.

Eastern Ontario and Western Quebec have historically been subject to periodic significant tornado outbreaks, including the recent September 21, 2018 tornado outbreak and a similar outbreak that occurred in the region on June 26, 1978. The June 1978 outbreak included a tornado affecting Masson-Angers, QC of very similar intensity, size and track length to the Dunrobin-Gatineau tornado of September 2018.

Due to the extremely complex nature of tornadoes and other severe thunderstorm hazards, understanding the effects of climate change on their behaviour has been challenging. Unlike other hazards, tornadoes are the result of a combination and balance of a set of meteorological conditions, which also helps to explain their rarity compared to other atmospheric hazards. Only relatively recently have detailed studies of climate change effects on severe thunderstorm activity been able to provide some indication of the potential effects of climate change over the North American continent.

Trapp et al. (2007) assessed the potential effects of climate change on severe thunderstorm activity by looking at two key ingredients, the potential energy available for producing thunderstorms and the atmospheric wind shear – defined as a change in wind speed and/or direction with height. Previous studies looking at overall average conditions suggested that energy will increase but wind shear will decrease under a changing climate, suggesting a possible "break even" condition in that no significant change will occur. However, by looking at the combination of these conditions rather than looking at their average individual change, Trapp et al. (2007) indicated the potential for an overall increase of up to a doubling of severe thunderstorm potential in some parts of North America. Diffenbaugh et al. (2013) further expanded upon this by investigating the change in conditions on individual days rather than longer term averages, finding that the average decrease in wind shear was mainly driven by changes on days *without* significant thunderstorm potential. The result was in fact an overall *increase* in the number of days with combination of high values of both potential energy and wind shear, especially for days with strong wind shear in the lowest portions of the atmosphere, which is particularly relevant for tornado production (Diffenbaugh et al. 2013). Furthermore, these changes were sensitive enough to climate warming that they occur by mid-century and/or under moderate warming (e.g. RCP4.5), and do not require an extreme warming scenario to develop (Diffenbaugh et al. 2013). These studies are further

[1] ECCC adopted the updated "Enhanced Fujita" or EF-Scale in April 2013 (ECCC, 2018) for the purposes of rating the intensity of severe thunderstorm winds and tornadoes based on their resulting damage. However, the historical dataset under the old "F-Scale" was maintained, and modern intensity ratings have been scaled to be roughly equivalent to historical events of similar intensity.

supported by the finding of Gensini and Brooks (2018) who report an observed increase in days with the potential for significant tornado development in the northeastern USA during the 1979-2017 time period.

As such, a conservative estimate of a 25% increase by mid-century (2050s) was applied to EF1+ tornado values for the future, with the annual probability of an EF1+ tornado impacting the Hydro Ottawa service area (City of Ottawa) increasing from an extended 48-year baseline value of 14.6% to a projected 18.2% in the 2050s under climate change. This projected increase in tornadic activity is consistent with other studies looking at future risks of EF2+ tornadoes (Strader et al. 2017) and considers some of the uncertainty associated with climate change projections of severe thunderstorm activity. Additionally, the results of Diffenbaugh et al. (2013) apply not only to tornadoes, but also to other severe thunderstorm hazards including extreme winds from thunderstorms (e.g. downbursts and "derechoes"), large and damaging hail, and even cases of extreme localised rainfall. This means that tornado events only represent a portion of the increase in projected severe weather days.

The point probability of an EF1+ tornado striking a specific Hydro Ottawa asset was also evaluated. Although the probability of a direct strike to a specific piece of infrastructure is very low, the annual point probability is also projected to increase under climate change with the baseline value of 0.018% projected to increase to 0.023% in the 2050s. Nevertheless, while the point probabilities are very low, a direct strike of a EF1+ tornado to infrastructure can result in considerable damage as was observed during the September 2018 outbreak and the direct strike of the Merivale station.

Invasive Species

Thresholds:

Emerald Ash Borer – $T_{min} \leq -30°C$ (kill temp.);

Giant Hogweed – 3 consecutive days with $T_{max} \leq -8°C$ (germination requirement)

Two invasive species of interest to Hydro Ottawa were evaluated in this study – Emerald Ash Borer and Giant Hogweed. Emerald Ash Borer (EAB) was highlighted by Hydro Ottawa due to the direct and indirect impacts on wood poles. EAB can potentially infest (and therefore weaken) poles and the introduction of EAB to the region has resulted in an increase in the woodpecker population, which is in turn damaging poles searching for the EAB. Giant Hogweed was highlighted by Hydro Ottawa as an occupational hazard to personnel due to the serious and potentially damaging impact the plant's sap can cause to skin and eyes. In this study, relevant temperature thresholds were evaluated corresponding to the invasive species (kill temperature for EAB mature, non-feeding larvae and temperature requirement for germination of Giant Hogweed seeds). As such, historical temperature baselines were established using data from the Ottawa Airport meteorological station and projections were generated using CMIP5 ensemble projections and the Delta Approach.

$T_{min} \leq -30°C$ represents the temperature at which EAB mature, non-feeding larvae will die. During the 1981-2010 baseline, an average of 0.5 days per year (annual probability of 53%) with $T_{min} \leq -30°C$ has been observed at the Ottawa Airport (**Figure C - 7**). In most years, $T_{min} \leq -30°C$ has been observed 0-1 days per year, with the exception of 2003 (2 days) and 1993 (6 days). Under climate change, the frequency of cold days is projected to decrease with $T_{min} \leq -30°C$ becoming a rare event (2050s projected annual probability of 3%). While the occurrence of $T_{min} \leq -30°C$ days are not expected to vanish completely due to the

amplified warming in the Arctic under climate change and the more unstable Polar Vortex, the probability of reaching the EAB larvae kill temperature is very low. Subsequently, the warmer winter temperatures will promote the survive of the EAB larvae. A recent study of underbark temperatures and emerald ash borer prepupae mortality has suggested that a reduction in the probability of prepupae mortality in Southern Ontario and the NCA has already occurred in response to warming winter temperatures (Cuddington et al., 2018).

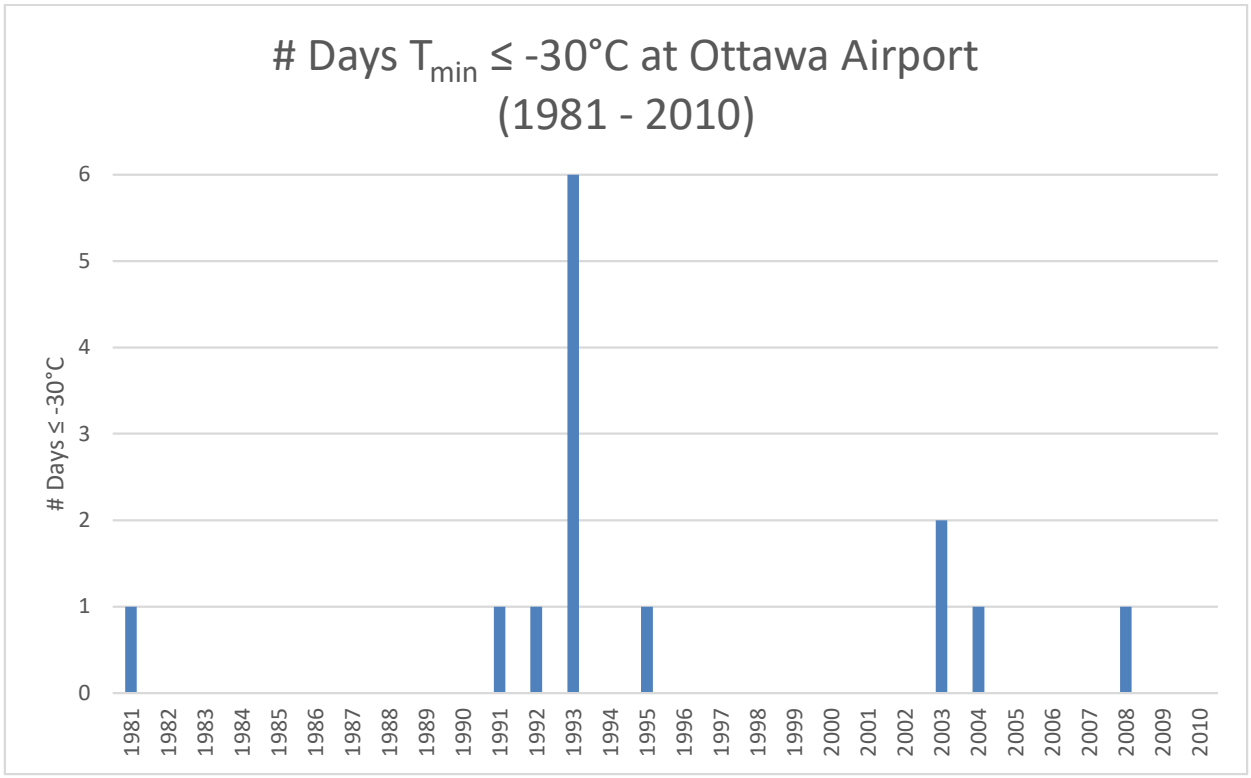


Figure C - 7. Number of days per year with the minimum temperature ≤ -30°C during the 1981-2010 time period at Ottawa Airport.

3 consecutive days with T_{max} ≤ -8°C represents the temperature requirement for germination of Giant Hogweed seeds. During the 1981-2010 baseline, 3 consecutive days with T_{max} ≤ -8°C has occurred on an average of 25 times per year at the Ottawa Airport. Under climate change, the frequency of these events is projected to decrease to an average of 17 times per year in the 2050s under the RCP8.5 scenario. Despite the projected decrease in frequency, the 3 consecutive days with T_{max} ≤ -8°C germination requirement will still be reached multiple times annually allowing continued spread and growth of Giant Hogweed in the Greater Ottawa Region.

Fog

Threshold:
Season with ≥ 50 fog days (Nov.-March)

Fog was evaluated for the winter months (November-March) by calculating the number of days per year with fog reported. Annual probability was evaluated for winters with 50 or more fog days, representing winters with fog observed 1/3 or more of the November-March season. Fog in the winter months promotes aerosolizing of salts

(e.g. road salt) which can cause corrosion to infrastructure and salt spray on insulators and conductors can cause pole fires and flashovers. A historical baseline for fog days was established using hourly data from the Ottawa Airport meteorological station and projections were generated using literature review and expert climatological judgment.

During the 1981-2010 baseline, winter fog has been observed an average of 49 days per year and with a decreasing frequency over the 30-year period (**Figure C - 8**). During this baseline, there is an annual probability of 37% for a winter with 50 or more fog days. Days with winter fog is likely to increase under climate change as winter temperatures warm, increasing moisture availability and promoting more evaporation in the region.

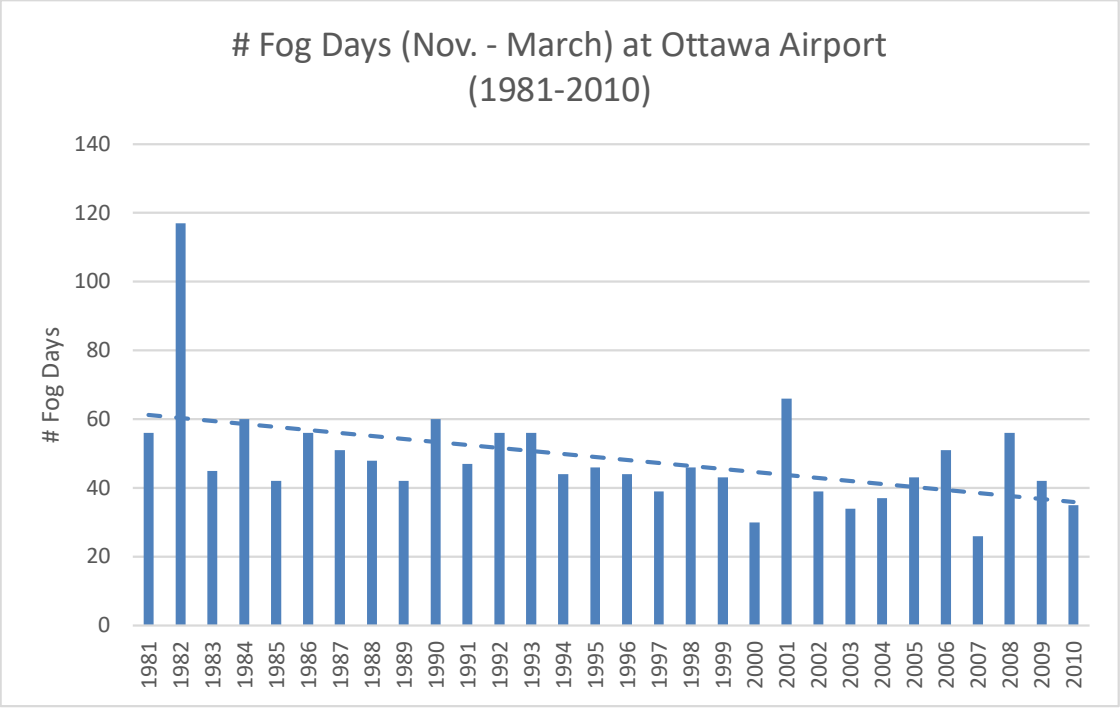


Figure C - 8. Number of days per year with winter (Nov.-March) fog reported at the Ottawa Airport during the 1981-2010 time period.

Frost

Thresholds:

Freeze-thaw cycles – Daily T_{max} T_{min} fluctuation around 0°C;

Hard Freeze-thaw cycles – Daily T_{max} T_{min} fluctuation of ±4°C around 0°C

Freeze-thaw cycles represent days (24-hr periods) where the maximum daily temperature (T_{max}) is greater than 0°C and the minimum daily temperature (T_{min}) is less than 0°C. Therefore, freeze-thaw cycles were evaluated by calculating the number of days meeting this criterion. Additionally, "hard" freeze-thaw cycles with a larger temperature fluctuation – $T_{max} \geq 4$°C and $T_{min} \leq -4$°C – were also evaluated. Larger temperature ranges in the freeze-thaw cycle can further promote the presence of moisture, which is required to cause damage to exposed infrastructure. Freeze-thaw probabilities presented represent the frequency of damaging cycles. Laboratory tests of un-reinforced concrete samples under combined structural loading and freeze-thaw

cycling found damage begins in the 20-40 freeze-thaw cycle range (Sun et al., 1999), indicating the selection of 30 freeze-thaw cycles as a lower bound. Therefore, the number of annual freeze-thaw cycles were divided by 30 for probabilities representative of damaging freeze-thaw cycles. Historical baselines were established using data from the Ottawa Airport meteorological station and projections were generated using CMIP5 ensemble projections and the Delta Approach.

The annual number of freeze-thaw cycles (T_{max} and T_{min} fluctuation around 0°C) is projected to decrease under climate change, from a baseline (1981-2010) mean of ~76 cycles per year to 59-60 cycles per year in the 2050s (**Figure C - 9**). Subsequently, the annual frequency of damaging freeze-thaw cycles (i.e. total number of cycles divided by 30) is projected to decrease from the baseline mean of ~2-3 times per year to ~2 times per year in the 2050s. Evaluating the monthly distribution of the number of freeze-thaw cycles reveals that the number of cycles per month during the 1981-2010 time period is greatest during the 'shoulder season' months (e.g. November and March) during the fall and spring seasons (**Figure C - 9**). While the number of freeze-thaw cycles is projected to decrease in many months under climate change, increases are projected for the months of December, January, and February, during which freeze-thaw cycles can be particularly damaging.

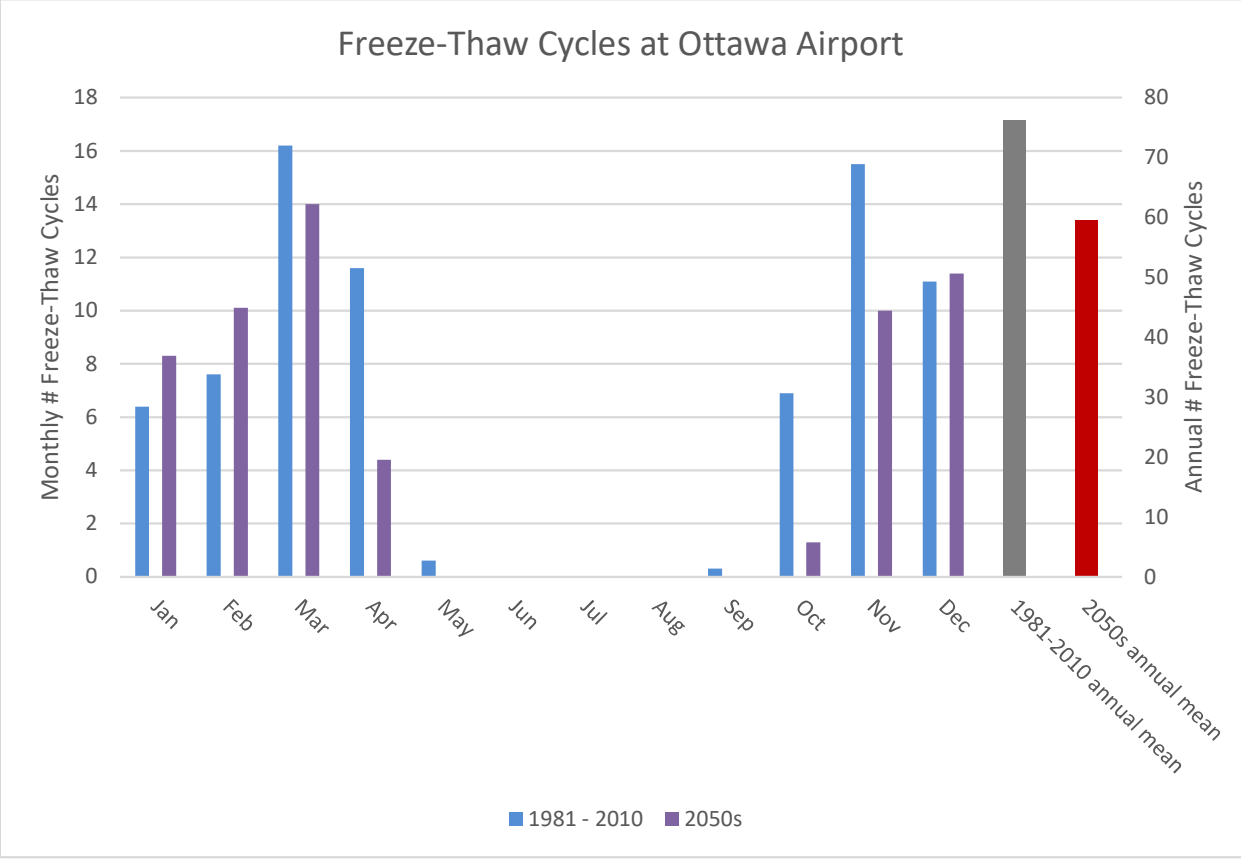


Figure C - 9. Monthly distribution and total annual number of freeze-thaw cycle at the Ottawa Airport during the 1981-2010 time period and projected for the 2050s under the RCP8.5 scenario.

The annual number of hard freeze-thaw cycles (T_{max} T_{min} fluctuation of ±4°C around 0°C) is projected to increase under climate change, from a baseline (1981-2010) mean of ~9 cycles per year to 11-12 cycles

per year in the 2050s (**Figure C - 10**). Subsequently, the annual probability of damaging freeze-thaw cycles (i.e. total number of cycles divided by 30) is projected to increase from a baseline of 30% to 38% in the 2050s. Evaluating the monthly distribution of the number of freeze-thaw cycles reveals that the number of cycles per month during the 1981-2010 time period is greatest during the month of March (**Figure C - 10**). Under climate change, the number of freeze-thaw cycles is projected to increase for the months of December, January, February, and March, during which freeze-thaw cycles can be particularly damaging.

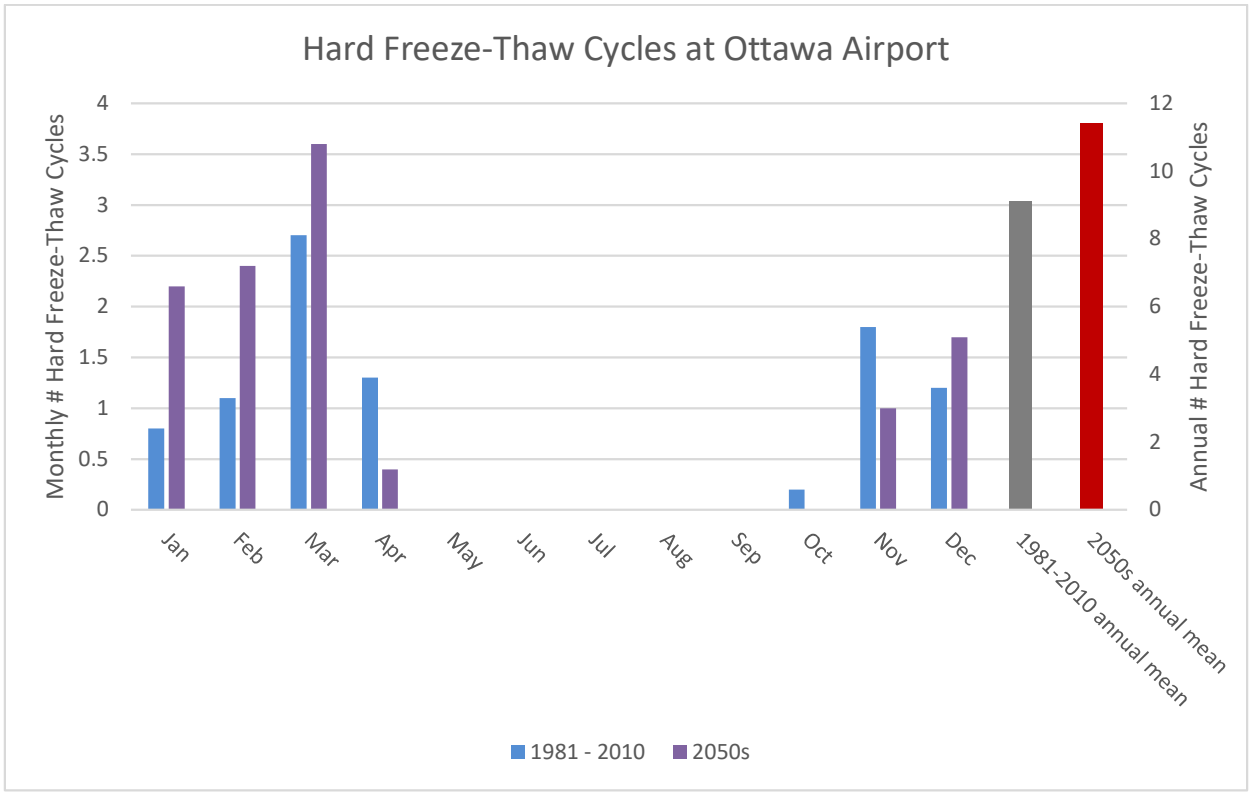


Figure C - 10. Monthly distribution and total annual number of hard freeze-thaw cycle at the Ottawa Airport during the 1981-2010 time period and projected for the 2050s under the RCP8.5 scenario. Hard freeze-thaw cycles are freeze-thaw cycles with a larger temperature fluctuation around 0°C, defined in this study a temperature fluctuation with $T_{max} \geq 4°C$ and $T_{min} \leq -4°C$.

Appendix B SUMMARY OF NOTES FROM INTERVIEWS



DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Appendix B Summary of Notes from Interviews
November 11, 2019

To:	Matthew McGrath (Hydro Ottawa),	From:	Riley Morris (Stantec), Guy Felio (Stantec)
Cc:	Nicole Flanagan (Stantec), Eric Lafleur (Stantec), Norman Shippee (RSI), Katie Pingree-Shippee (RSI), Simon Eng (RSI), Heather Auld (RSI)		
File:	Hydro Ottawa Climate Risk Assessment and Adaptation Plan – Interview Results Summary	Date:	November 11, 2019

PREAMBLE

Hydro Ottawa has retained Stantec Consulting Ltd. to conduct a climate change risk assessment 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. 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 1**. 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 will help to identify the climate risks that Hydro Ottawa are exposed to and to gain 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 herein.

PARTICIPANTS

The following participants attended the interview sessions that took place on March 7-8, 2019.

Table 1 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 Boldock	Manager, System Operations
Brian Kuhn	Manager, Distribution Operations (Overhead)
Adam MacGillivray	Business Continuity Management Specialist

CLIMATE PARAMETERS

Wind Events

All participants agree that the intensity and frequency of wind storms has increased in recent years. Wind damage is more prevalent in the north end of Ottawa. The typical path of wind storms is from Kanata towards Crystal Bay and then along the river.

- Wind storms that affect Ottawa do not seem to affect Casselman.
- Sustained winds and gusts were noted to be an issue.
- Wind speed that causes damage to trees depends on the period of the year, i.e., if trees have foliage or not. It was mentioned that with foliage, branches can occur at winds of 60 km/h; with no foliage, winds of more than 80 km/h.
- East-West power lines generally have little impact.
- North-South power lines are vulnerable.
  - North-south power lines are guyed for protection from prevailing winds (from the West).
  - Most intense storms that cause damage come from the East, staff feel that guying should be done from both directions.

- Particularly vulnerable lines include rural lines; for example, Greenbank Road, Fisher Avenue, Limebank Road.

Microbursts

Note: Environment Canada defines a Microburst as "a downburst (strong convective downdraft resulting in an outward burst of often damaging winds at or near the surface) less than 4 km in horizontal dimension. Microbursts tend to have a shorter lifetime and be more intense than larger downbursts and can result in damage intensity similar to that associated with a strong tornado."

- Damaging, especially if coming from the East (poles are guyed from the West).
- Noticed that they occur more often than in the past.
- Knock down older – more vulnerable poles, trees and cause damages to surface infrastructure.

Tornados

- "Can't really do anything except pick up the wires afterwards".
- Areas of improvement include better forecasting to alert employees and contractors, and to mobilize crisis management team.

Specific Instances

- High sustained winds (April 28, 2012) – Lost 3-4 poles, delayed restoration, took hours to recover.
- Remnants of Hurricane Sandy (November 2012) – Cold wind, bucket swaying during maintenance, safety concerns.
- Microburst in Gloucester at Blair and Ogilvie (early-mid 1990s, summer) – Lost a lot of poles.
- Microburst in Lincoln Fields area.
- Tornados of 2018.

Freezing Rain

- Pole fires are common during freezing rain events (electrical current travelling via moisture/dust/salt on conductors/insulators to the pole, which heats up and catches fire). Occurs near 0°C as temperatures are rising + precipitation.
- Flashovers possible.
- To avoid pole fires and flashovers, Hydro Ottawa may sometimes wash porcelain insulators.
- Freezing rain conditions can limit operators/maintenance teams' ability to access impacted areas.
- The weight of ice accretion could cause structural issues or lines to sag. This is not too significant unless there is also wind. The combined effect can cause problems at 1/2 inch of ice accretion + 90km/h winds.
- Ice accretion on switchgear could cause difficulties in switching, each equipment has its own operable limits for ice cover (on the order of 10mm). Near 0°C, it is usually easy to remove accumulated ice off of switch.

- Damages to distribution network are often tree-related (broken limbs, etc.) – severity depends on level of foliage and whether leaf-out has occurred. A lot of damage from tall trees that have limbs that hang above power lines.
- Freezing rain of any quantity is concerning, however, a quantity of 10mm was identified as a possible threshold where Hydro Ottawa starts closer monitoring of the system.
- The impacts of freezing rain are not as severe when it turns into rainfall.

Specific Instances

- The 1998 ice storm was a major issue for Hydro Ottawa.
- Freezing rain storm on April 16, 2018 was memorable for emergency planning team.

Lightning (Atmospheric discharges)

- Not a significant issue.
- May blow transformers, breakers, fuses under direct strike (1-2 instances per year).
- Noticed that thunderstorms recently last longer and that they typically occur more frequently.
- Lightning damage is more prominent in southern Ottawa.
- Lightning protection system design frequency: 1 flash/km^2/year.
- Arrestors aren't actively maintained. Arrestors blow when lightning strikes a pole and can handle a few nearby strikes. Once every 3 years an arrestor replacement program is done.
- Placement of lightning arrestors is much better than in the past
- There are lightning rods at some substations
- Lightning may be a concern if it increases in the future

Heavy Rainfall and Flooding

Rainfall

- No real issues directly caused by rainfall itself.

Flooding

- Electrical equipment in low-lying areas are vulnerable. For example: ponding around vaults, underground equipment, or low pad-mounted/backyard transformers/switchgear is of concern. Transformer will fail if transformer box fills with water. Flow into civil structures or chambers from ponding is an issue.
- Ponding issues are less worrisome in the summer, however during winter melt or rainfall events, frozen ground, ice damming, and iced-over grates exacerbate flooding potential and problems.
- Issues from flooding/ponding are common during spring ice melt.
- Older neighborhoods did not sufficiently plan for flooding and are more vulnerable. Drainage design in new subdivisions is likely to reduce flooding problems.
- Hydro Ottawa can provide input during drainage design stages for subdivision planning.
- Hydro Ottawa relies of the City of Ottawa storm water management system.

Specific Instances

- Flooding event in 2017 – Vaults on Riverside Drive were flooded

Humidity

- Under high humidity, “air gear” (a component of the switchgear) rusts out prematurely from condensation and pooling of water when improperly vegetated. They’ve found that it is cheaper to replace more often than to heat or ventilate to relive moisture n switching centers.

Extreme Temperatures

- Equipment/infrastructure specifications typically has a design temperature range of -40°C to +40°C (ambient).

Extreme Heat

- Heat is not so much an issue for infrastructure.
- Issue in terms of heat advisories are primarily for personnel.
- Extra loading on system (from A/C use) could cause system crashes – load distribution may be required.
- Conductors expand, and lines may sag in the heat – this is not seen as a major issue. The system and components are designed for up to+40°C ambient temperature.
- Most devices are passively cooled.

Prolonged Heat (heat waves)

- After more than three days of heat (mid-30°s) loading capacity issues in the system arise.
- System overloading is common due to extensive A/C use throughout the city. When trying to switch overcapacity loads, breakers often trip. To avoid this, it is often more favorable to overload the equipment (which have short-term overload capabilities) instead of switching. Doing this, however, the equipment needs time to intermittently cool down, if heat continues through the night, it does not get this cool-down time.
- Frequent equipment tripping reduces its life span.

Extreme Cold

- Similar to extreme heat, extreme cold temperature is not viewed as a major issue (equipment design to -40°C ambient temperature), but cold advisories for personnel is required.
- Electric baseboard heating is more common in older areas of Ottawa; these sections can be overcapacity under extreme cold events.
- In extreme cold, switchgear is tight and brittle and very difficult to operate when Hydro Ottawa needs to manually switch loads.

Specific Instances

- Heat waves in 2009 and 2010.

Snowfall

- Concerns about snow events relate to snowplows that damage on-grade infrastructure (ex: transformer collars, transformers, switchgear).
- Access issues can also occur if on-grade equipment and infrastructure are covered in snow.

Freeze-Thaw

- Flooding can result from winter melt or rainfall events, frozen ground, ice damming, and iced-over grates and can impact underground or grade-level infrastructure.
- Freezing moisture can cause failure in underground cabling. If ducts are frozen, crews cannot access to do work.
- There have been more mid-winter freeze-thaw events recently and therefore more pole fires.
- Impacts from the amount of calcium spread during freeze-up events: increased calcium spread results in salt spray onto insulators and conductors which can cause flashovers and pole fires

Wild (forest, grass) Fires

- Grass fires can sometimes turn into forest fires, rural infrastructure can be at risk.
- Even if Hydro Ottawa is not directly at risk, their suppliers' risk (e.g., Hydro One) may be transferred to Hydro Ottawa if their supply lines are affected.

Insect Infestations/Invasive Species

- Increased woodpecker damage to hydro poles (introduction of emerald ash borer caused a spike in the woodpecker population).
- Ticks and giant hogweed are an occupational hazard now for operation/maintenance personnel.
- Shift in vegetation species may impact vegetation management program (growth time, methods, etc.).

GENERAL NOTES

General Comments

- All participants agree that although storm frequency is fairly consistent, storms are getting increasingly more severe; more extreme events are occurring.
- It was noted that there has been a shift in electricity demand peaks in recent years. In the past, winter was a peak demand period for heating; however, customers are converting to gas as heating fuel, and becoming more energy conscious. A/C is becoming standard in houses/offices where it once was a "luxury"; this now results in summer-peaking demand. Because of reduced demand peaks and generally high system performance, Hydro Ottawa has seen fewer system overloading in recent years.
- Major insurance repercussions (in the millions of dollars) if Mutual Assistance Groups are not contacted during an emergency event.
- Casselman does not appear to be impacted as much as Ottawa: this may be a result of storms generally tracking closer to the river and typically not reaching Casselman, or possibly because the electrical system is more robust. Nonetheless, there are less emergencies in Casselman.
- Forecasting: Environment Canada, DTN, The Weather Network - forecasting services getting more expensive for Hydro Ottawa.
- More investment in infrastructure and programs increase rates, which displease the public; however, major event days and the rapid response and restoration of service reminds the customers of the need for robust infrastructure.
- Climate change (e.g. increase in extreme events, higher summer temperatures, lower winter temperatures) will likely cause a shift in their service peaks.
- Hydro Ottawa has never closed their offices due to weather events; however, they have asked people to work from home under extreme conditions (e.g., tornados). Hydro Ottawa recently procured a new intra-company alert system (for all hazards, not just weather).



Event Response

- Hydro Ottawa averages two “Major Event Days” per year; operations believe that this will increase over time.
- Definition of Major Event Day: statistical calculation based on the SAIDI measure exceeding a threshold of 5.5 (IEEE Standard 1366). SAIDI: System Average Interruption Duration Index – The average outage duration for each customer serviced
- Challenges depend on when (time of day) the event occurs, and at times to coordinate staff and their work/sleep schedules can be difficult, particularly during a major event day.
- On a typical day, operators work during the day with a group on call at night
- On a major event day, all available staff work during the day and all staff sleep at night to be ready to start in full force at 6am the next morning with the exception of a small crew who remain at night to manage and operate the systems/communication/monitoring. This is a new practice that is thought to be more efficient and safer for the field crews.
- Hydro Ottawa receives tailored alerts from forecasters. Based on these, forecast and experience, a judgement call is made on how to manage staff
- Emergency planning team feels that they are getting better at responding

Third Party Risks

- Pole availability issues: forest fires in BC have made sourcing wooden poles difficult.
- What telecommunications companies manage with their assets can affect Hydro Ottawa. For example, communications towers lost power during the September 2018 tornados. Hydro Ottawa lost radio, email, and phone capabilities. Because of a critical asset agreement with Bell, they were able to get Bell crews to restore communications within an hour.

Plans, Programs, and Tools

- Storm Hardening Plan
  - Plan was a reaction to 2013 Toronto ice storm.
  - Vegetation Management Plan (VPM): Began quality control program as part of new VMP. Identification of tree species and removing those that are likely to cause issues or rather cutting them back further than the standard 10’ radius from lines. Also removing diseased or vulnerable trees, including those that have shallow root systems that could fall onto lines. This plan also includes an education component, for example, telling the city where to plant trees that won’t affect their infrastructure.
- Mutual Assistance Groups in which Hydro Ottawa participates
  - Canadian Mutual Assistance Group (CANMAG)
  - North Atlantic Mutual Assistance Group (NAMAG)
  - Quebec Regional Assistance Group (QRAG)
  - Hydro One and Hydro Ottawa will help each other when in need

- Business Continuity Plan
  - Business Impact Analysis on mission critical processes
  - Enterprise Risk Management Group looked at risk identification
  - Emergency Response Plan
  - Crisis Management Plan
  - Incident Management Tool: itemized tool of instructions so that in an emergency, anyone can perform system operation procedures. Each mission critical process has a manual work around.

Areas in which Hydro Ottawa shows Innovation

- Hydro Ottawa currently building new headquarters, which will bring more connectivity among staff and resources, more technology, new SCADA more data for tracking and alerts. New work from home policy (incl. all employees to have laptops) will improve business continuity.
- New equipment, for example, backyard bucket to access backyards and limited access areas including off-road.
- Transition from overhead to underground services has reduced environmental exposure
  - New subdivisions are underground
  - New trunk feeds are underground
- Hydro Ottawa has requested Public Safety Canada to list it as critical infrastructure, which they are currently not. This, for example, would give Hydro Ottawa access to critical radio services.

Areas in which Hydro Ottawa improve

- Hydro Ottawa could have a better alert system. For example, there was not adequate warning for the September 2018 tornados to properly activate the Crisis Management Plan which would have strengthened communication among different response groups, gathered external resources, and would have allowed Hydro Ottawa to contact Mutual Assistance Groups (MAGs) with more notice. In this case, by the time the MAG aid arrived, little assistance was needed.
- To protect North-South power lines, staff feel that poles should be guyed from both the West (where prevailing winds come from) and the East (where intense storms come from), instead of just the West. Alternatively, it was suggested installing a concrete pole every 5-10 poles as anchor poles so the whole line doesn't fail in a storm.
- More intensive vegetation management would reduce impacts. Currently limited to a 10' radius around the powerlines.
- In general, there is interest within the company to adapt to climate change (particularly in the last 1-2 years), but there is no clarity on how to do so.

Benefits of extreme weather events and climate change

- Extreme events can point to the vulnerabilities in the system and help strengthen weak and vulnerable assets.
- Shorter winter seasons may result in a longer construction season
- Improvements to response and preparedness with each event.
- Potential increase in sales of electricity due to increased summer demand

Appendix C SUMMARY OF NOTES FROM WORKSHOP



Notes from Hydro Ottawa 12 April 2019 Workshop

FEEDBACK ON CLIMATE PARAMETERS AND THRESHOLDS

Tmean ≥ 30°C:

- Hydro Ottawa has noticed sensitivity of their equipment to this climate parameter/threshold
- However, it's more of an issue when there's a heat wave….
  - Loading on transformer after the third day becomes the big issue, equipment is unable to cool down properly
- Implications for health and safety of staff working outdoors (can postpone regular maintenance, but at some cost, but not repair responses)
- Consider use of critical limits for CDD, as per note on additional parameters.

Extreme Minimum Temperatures:

- Hydraulics on trucks – may be sensitive to temperatures ~-35°C and colder
- Slower crew responses. Also, crew equipment (e.g. safety gloves) may not respond well (e.g. require bare hand work).

Heat Waves:

- The warm Tmin associated with heat waves is more representation of when Hydro Ottawa system is impacted than the Tmax
- Tmax ≥ 30°C impacts the personnel while the warm Tmin results in increased stress on the electrical system (e.g. loading and transfer of loads to different circuits, equipment unable to cool down properly)
- Tmin of 23°C and 25°C were mentioned (25°C seemed to be mentioned more)
- Therefore, they would be interested in Tmax ≥ 30°C + Tmin ≥ 25°C (or 23°C) for heat wave definition

Extreme Rainfall:

- Hydro Ottawa confirmed no vault flooding due to extreme rainfall
- Any flooding issues were due to riverine flooding (spring, +snowmelt-driven flooding) – 1 Riverside vault has been flooded due to the Rideau River flooding with a ~30-yr frequency (once in the Spring of 1986 or 87 and again in the Spring of 2017)
- Hydro Ottawa noted that buried equipment is submersible and equip to deal with water/flooding
- For health and safety reasons, repair crews may not be able to go aloft in trucks for extreme SDHI events, leading to longer period of power outage before repairs.

Freezing Rain and Ice Storms:

- Freeze thaw and the accumulation of ice speeds up wear and tear
- Freezing rain/ice accretion + wind is the big issue
- Uneven ice accumulation can lead to "galloping" of the lines at wind speeds lower than 90 km/hr
- Design load: ½ inch ice + 90 km/hr wind



- May pose restrictions on times for repair crew responses due to health and safety risks i.e. longer to reach sites, fallen tree branches on roads, slip and fall risks, and use of truck buckets.
- Could add – failure of communications infrastructure will impact responses and their coordination.

High Winds:

- High gust events are an issue because they create spot events (e.g. broken pole)
- Larger spatial scale sustained wind events are also an issue and make life more complicated because, while the individual issues are smaller, it means the crews are deployed over a larger area
- Wind thresholds for restrictions on operation of truck buckets not clear (also issues for falling tree branches). For power outages, this would affect the ability to respond to outages and duration of outages. Question - if a crew member works in high wind or other risky situation and the bucket truck tips or boom drops, who would be blamed? Likely the crews.
  In UK, booms designed up to **35 mph**, after which the boom can collapse. Also, boom could be deflected into distribution infrastructure, with risks if system is wet. Buckettrucks.org website claims "Do not operate the boom **if wind gusts exceed 30 mph** or there is a threat of an **electrical storm**". So, 30 mph = **48 kph**. Suspect that workers do not adhere to this limit.
- Issues associated with flying debris, particularly for exposed sub-station equipment (i.e. higher severity than for a building, for example) – wind thresholds for flying debris likely around 60 kph? City of Calgary's criteria for flying construction debris: 41 - 50 km/h raises sheet metal, aluminum, 20 gauge; half-inch plywood sheet; steel stud, half-inch diameter plastic pipe; Winds 75 - 89 km/h raise half-inch nut, scaffolding, five-eighth-inch drywall sheet, plastic pipe/conduit, four-inch diameter
- Flying debris also poses a staff (repair crew) safety issue
- Note than Casselman station may have issues with flying debris (exposed substation(s), lumberyard across road, abandoned McDonalds adjacent)

Winter Fog, Light Drizzle:

- Hydro Ottawa has a washing program for insulators: twice a year (fall and spring) every year. This is preventative action against seasonal salt buildup on lines, other equipment that can result in fires, outages.
  - Spring washing occurs in mid-March or early April (essentially as soon as the temperature warms up) since winter build-up of salt + warm-up can cause pole fires.

Additional Parameters:

- During the workshop Heather and I got wondering if it's worth adding HDD/CDD and smog/AQ days (didn't discuss with Hydro Ottawa people, just wrote down the thoughts). CDD and HDD threshold would relate to the first severity score for System Accessibility, Sa, where load demand could exceed planning limits. Need some means to relate CDD and HDD to these planning limits.
- Under more extreme weather events, there will likely be a call for mutual aid and need for lodging, food, coordination. The severity of the weather hazard will impact these responses.

Snow Events

- Not much insight provided on different types of snow events other than access issues.

Lightning Events

- Again, not much discussed here.
- Health and safety issue? Crew in buckets repairing systems in an intense lightning storm?
- Cascading Impacts and severity were often mentioned e.g. several of the severity scores interact, as in extreme event triggers widespread power outages which in turn impact ability to respond quickly, efficiency of access and of equipment used to restore system, health and safety of employees, etc. As well, wind on ice or wet snow and directionality can greatly exacerbate impacts.

FEEDBACK ON (ADDITIONS TO) INFRASTRUCTURE LIST

- Hydro fibre
- Residential metering
- Overhead load break switches
- Underground urban infrastructure (e.g. vaults in the downtown core)
- Food services (3rd party) as part of emergency supplies
- Lodging (3rd party) during emergency response

MISCELLANEOUS INFORMATION GATHERED DURING WORKSHOP

- Hydro Ottawa indicated that they discuss the level of risk they are willing to accept and that helps to inform the severity rating for the matrix
- At Casselman:
  - There is no substation building, all equipment is “outdoors” and in cabinets as necessary
  - Cabinets have a heating component but no AC (only fans to ventilate/circulate the air through the cabinet)
  - Casselman station is a ‘two-legged station’ with build-in redundancy
  - Casselman station is across the street from a lumberyard and next to an old McDonald’s Golden Arches (McDonalds moved ~15 years ago so arches have not been maintained)
  - Hydro Ottawa has people on contract in Casselman who can deal with immediate issues. If Hydro Ottawa has to go on-site to fix an issue, it currently takes them up to 1.5 hours to get there (will be ~45 minutes once they move to their new location)
  - There are 3,400 customers in Casselman (residential and businesses)
  - Village of Casselman provides road and storm sewer maintenance
  - Hydro One provides power to Casselman station
  - Bell and Rogers provided telecommunications (copper and fibre)
- Temp < -40°C: metres work (in heated cabinets) but communication system may not
- Transformers are susceptible to windblown debris
- Ground grid is buried 12-18 inches deep; the tails/whips are the exposed and therefore concerning part of the equipment

- There was various discussion on the minimum wind speed that prevents employees going aloft in the bucket trucks (30 km/hr was indicated but there was no definitive speed determined, sounds like it depends on the individual crews deployed) – see above under winds
- “Service equipment” (under “Service and Personnel” on the matrix) was defined as field equipment/tools necessary to complete the job, including portable generators, hot sticks, Class 4 high voltage gloves
- Crews don’t work in extreme rainfall due to Health and Safety reasons – see above under rainfalls
- Freeze-thaw cycles can lead to ice build-up which becomes a Health and Safety concern e.g. breaking hands
- Hydro Ottawa gets fuel from the City of Ottawa and the City gets fuel delivered in – multiply days of heavy snow is needed before the fuel reserve would become an issue



Appendix D RISK WORKSHEET (CURRENT AND FUTURE)

| Asset/Infrastructure Element | Performance Considerations | | | | Maximum Temperature | | | |

| Asset/Infrastructure Element | Performance Considerations | | | | Maximum Temperature | | | |

| Asset/Infrastructure Element | Performance Considerations | | | | Maximum Temperature | | | | | | | | | | | | | | | | Minimum Temperature | | | | | | | | | | | | | | | | Heat Wave | | | | | | | | | | | | | | | | Extreme Rainfall | | | | | | | | | | | | | | | | Freezing Rain/Ice Storm | | | | | | | | | | | | | | | |

Asset/Infrastructure Element	Performance Considerations				Maximum Temperature		Minimum Temperature	Heat Wave	Extreme Rainfall	Freezing Rain/Ice Storm		High Winds				Snow	Frost (ground)	Fog
					Climate 1	Climate 2	Climate 3	Climate 4	Climate 5	Climate6	Climate 7	Climate 8	Climate 9	Climate 11	Climate 10	Climate 11	Climate 12	Climate 13
Current Climate	Level of Service, System Accessibility, Legal Liability, Service Quality	Resource Efficiency	Asset Value - Financial		Daily maximum temp. of 35°C and higher	Daily maximum temp. of 40°C and higher	Daily minimum temp. of -35°C and colder	Heat wave: Consecutive days with Tmax ≥ 30°C and Tmin ≥ 25°C	50mm of rainfall in 1 hour	Ice accumulation of 25 mm	Ice Accumulation of 40mm (50-year occurrence)	Easterly winds of 60 km/hr or higher (warm season (April -Sept.))	Easterly winds of 80km/hr or higher (cool season (Oct-March))	Annual wind speeds of 120 km/hr or higher	Annual wind speeds of 120km/hror higher (30-year occurrence)	Days with 30 cm or more of snowfall	Freeze-thaw cycles – DailyTmax Tmin temp. fluctuation of ±4°C around 0°C	Season with ≥ 50 fog days (Nov.-March)
					Probability = 5	Probability = 5	Probability = 1	Probability = 3	Probability = 1	Probability = 2	Probability = 4	Probability =2	Probability = 2	Probability = 1	Probability = 3	Probability = 2	Probability = 3	Probability = 4
					Final	Final	Final	Final	Final	Final	Final	Final	Final	Final	Final	Final	Final	Final
	Sa	Sg	Se	Sf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf	Y/N Sa Sg Se Sf Ra Ro Re Rf
1) City of Ottawa																		
1.) General System-Wide Assets																		
Buildings																		
Administrative and Operational Buildings					Y 4 20	Y 4 20	Y 1 1 1 1 20	Y 1 1 2 2 Y 4 4 16 16	Y 1 1 1 1 20	Y 1 1 2 2 Y 4 4 16 16						Y 1 1 2 2 Y		
Roof (Sloped)																		
Roof (Flat)																		
Envelope															Y 4 12			
Structure																		
Foundation																		
Gas																		
Attached Equipment															Y 4 12			
Substation Buildings					Y 4 20	Y 4 20			Y 1 1 1 1 20	Y 1 1 2 2 Y 4 4 16 16						Y 1 1 2 2 Y		
Roof						Y 1 5												
Envelope															Y 4 12			
Structure																		
Foundation																		
Gas						Y 1 5												
Attached Equipment															Y 4 12			
Substations																		
Buildings and Structural Components					Y 4 20	Y 4 20	Y 1 1		Y 1 1 1 1 20	Y 1 1 2 2 Y 4 4 16 16						Y 1 1 2 2 Y		
P&C Buildings																		
Switchgear Buildings																		
Equipment Support Structures																		
Station Yard																		
Station Load Break Switch						Y 1 5	Y 1 1 1			Y 1 1 2 2 Y 4 1 1 16 4 4								
Station Capacitor Voltage Transformers						Y 1 5												
Station Circuit Breakers						Y 1 5	Y 1 1 1											
Indoor Breakers																		
Outdoor Breakers (Metalclad)						Y 1 5	y 1 1 1											
Station Power Transformers																		
Surge Arrestors																		
Bushings																		
Radiators																		
Fans																		
Control Cabinet																		
Tap Changer																		
Bushing Enclosure																		
Conservator																		
Monitoring and Protection Systems																		
Online Dissolved Gas Analyzer							Y 1 1											
Core, Windings, Oil						Y 1 5												
Station Metering																		
spaces)																		
Batteries (INDOOR - o/k; OUTDOOR...)							Y 1 1											
Battery Charger																		
Protection Relays																		
Instrument transformer																		
Electro-Mechanical Relays																		
Microprocessor Relays																		
Station Grounding and Ground Grid																		
Equipment																		
Station Miscellaneous Equipment																		
Busbar																		
Station Post Insulator															Y 1 4 3 12			
Lightning Rods and Arrestors															Y 1 4 3 12			
LV Power Transformers						Y 1 5												
Cable Trenches																		
Cable Trays																		
Cables						Y 1 5												
Station Lighting																		
Services and Personnel																		
Service Vehicles										Y 1 4 4 1 2 8 8 2 N								
Service Equipment									Y 1 4 4 1 1 4 4 1									
Staff and Occupational Health and Safety																		
Operators						Y 9 4 45 20	Y 1 1		Y 1 1	Y 1 1 2 2 Y 9 4 36 16					Y 4 4 4 8 8 8	Y 4 4 4 8 8 8	Y 4 4 4 12 12 12	Y 4 4 4 8 8 8	Y	Y 1 1 4 4
Preventive Maintenance Staff						Y 9 4 45 20	Y 1 1		Y 1 1	Y 1 1 2 2 Y 9 4 36 16 Y					Y 4 4 4 8 8 8	Y 4 4 4 12 12 12	Y 4 4 4 8 8 8	Y	Y 1 1 4 4
Support Staff											Y 4 1 16 4					Y 1 1 2 2 2		
Communications, Smart Grid and Metering																		
Hydro Ifiber																		
Residential Metering																		
Third Party Services and Interactions																		
Hydro One											Y 9 9 36 36				Y 9 9 27 27			
Power Supply						Y 1 5												
Shared Infrastructure																		
Attached Equipment																		
City of Ottawa																		
Drainage																		
Winter Maintenance																		
Telecommunications																		
Bell & Rline Lines																		
Fuel Supply																		
Hydro Ottawa Subsidiaries																		
Energy Ottawa																		
Envari																		
Emergency Resources																		
Logistics (Food Services, Lodging)																		
1.) Ord Substations, Rural and Transmission																		
Power Distribution - Overhead (East-West Orientation)																		
Distribution Lines						Y 1 5			Y 4 4 8 8 Y 9 4 4 36 16 16 Y						Y 9 9 9 27 27 27			
Primary Overhead Conductor																		
Secondary Overhead Conductors																		
Ground Conductors																		
Third Party Equipment																		
Poles											Y 9 4 4 36 16 16				Y 9 9 9 27 27 27		Y 4 1 1 16 4 4	
Pole (Wood)																		
Pole (Concrete, Composite, Metal)																		
Cross Arms																		
Guy Wires and Anchors																		
Insulators																	Y 4 1 1 16 4 4	
Surge Arrestors																		
Overhead Transformer						Y 1 1 9 5									Y 1 1 1 3 3 3			
Enclosure																		
Primary Bushing																		
Secondary Bushing																		
Tap Changer																		
Hanging Lugs																		
Overhead Load Breaker Switch											Y 4 1 1 16 4 4							
Ground Connection																		
Surge Arrestors																		
Fused Cut Out											Y 1 1 1 4 4 4							

2026-2030 Custom IR
EB-2024-0115
Interrogatory Response
2-Staff-41
Attachment A
ORIGINAL
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| Asset/Infrastructure Element | Performance Considerations | | | | Maximum Temperature | | | |

| Asset/Infrastructure Element | Performance Considerations | | | | Maximum Temperature | | | |

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-42

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / pp. 56-57 (pdf Exhibit 2 part 2, pp. 56-57)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 4 / p. 136 (pdf Exhibit 2 part 3, p. 136)

Preamble:
Hydro Ottawa states that there are significant increase in demand in regard to ""growing adoption of electric space heating", forecasted large loads ("Hydro Ottawa anticipates an unprecedented 312 MVA increase in its total load demand over the 6 year span of 2024-2030"), significant population growth ("Ottawa population Compound Annual Growth Rate (CAGR) of 1.3% and dwelling CAGR of 1.5% between 2026 and 2031 as per the City of Ottawa Official Plan.") and transportation electrification ("60% of all light duty vehicles sold in Canada to be electric vehicles by 2030 and 100% by 2035").

QUESTION(S):

a) Considering the slowdown of electric vehicle (EV) sales in Q1 2025 vs Q4 2024, how has Hydro Ottawa revised forecasts for electrification segments (electric space heating, EVs, etc.) for 2050?
    i) Please provide details on the calculation.
b) requests vs actual amount that is constructed?
c) Please discuss if the housing projection is being reconsidered given the soft housing starts in Ontario in 2025Q1. [1]
d) Please discuss any adjustments being implemented to the Transportation Electrification Factor given the most recent EV sales figures.

[1] Yahoo Finance Canada. (2025, June 17). Ontario housing starts fall to lowest level since 2009. Yahoo Finance. Link.

e) Is the City continuing with the target of 354 electric bus procurement by 2027 and a full transition to electric buses by 2036 or have the targets been modified? Please discuss.

RESPONSE(S):

a) Hydro Ottawa's Decarbonization Study (Attachment 2-5-4(F) - Decarbonization Study) forecasted multiple scenarios to capture different paces of decarbonization/ sensitivity analysis that meet Canada's 2030 Emissions Reduction Plan and 2050 decarbonization goals in alignment with the Ontario Energy Board's Load Forecasting Guideline[2] through the Regional Planning Process Advisory Group.

As per Table 38 in Section 9.4.2.1 of Schedule 2-5-4 - Asset Management Process, EV-related load in the Policy-Guided Scenario is projected to increase significantly - consistent with Canada's Zero-Emission Vehicle Sales Target, which mandates 100% of new light-duty vehicles (LDVs) sold in Canada to be zero-emission by 2035. In contrast, the Low Case Sensitivity scenario directly addresses slower adoption rates, as outlined in the question. It models a slowed pace of EV adoption, with projections indicating EVs will comprise 40% of new sales by 2035 and 90% by 2050. This scenario acknowledges that a substantial portion of the vehicle fleet may remain gasoline or diesel-powered beyond 2050 if adoption is slower.

The same multi-scenario approach applies to building electrification, with the Policy-Guided Scenario representing an aggressive decarbonization pathway having residential heating (both water and space heating) projected to be 100% electrified by 2050. The Low Sensitivity scenario for the building sector assumes a less aggressive electrification, where efficiency gains from converting existing electric resistance heating to higher-efficiency heat pumps or low-carbon gas could lead to a decline in total load in later years.

[2] Regional Planning Process Advisory Group, Load Forecast Guideline for Ontario (October 13, 2022): https://www.oeb.ca/sites/default/files/Load-Forecast-Guidance-Document-RPPAG-20221013.pdf

By utilizing these multi-scenario forecasts for long-term planning and continuously incorporating updated industry trends, Hydro Ottawa is well positioned to adapt to potential shifts in customer adoption rates and external policy drivers.

i) Since Hydro Ottawa has not revised any forecast scenarios due to slowdown of electric vehicle (EV) sales in Q1 2025 vs Q4 2024, subsequent calculations cannot be furnished. However, Hydro Ottawa believes that the Low Sensitivity scenario most closely aligns with reduced EV sales. The assumptions used in this scenario can be found in Page 28 of Attachment 2-5-4(F) - Decarbonization Study.

b) At present, Hydro Ottawa is in the nascent stages of gathering data pertaining to decarbonization, and in the initial planning phases for electrification projects slated for energization between 2026 and 2030. Hydro Ottawa intends to continuously monitor and track data comparing forecasted requests against actual constructed amounts as these projects reach energization. The utility anticipates being able to provide more robust data analysis and reporting once a sufficient volume of information has been amassed and processed from both ongoing and completed initiatives.

c) Hydro Ottawa uses the City of Ottawa's growth projections, as outlined in Section 6.5.2 - Residential Growth - Schedule 2-5-4 Asset Management Process, to forecast housing for load planning. Hydro Ottawa will continue to align with these projections, supplementing them with annual housing start data for sensitivity analyses to ensure our investment plans accurately reflect actual housing developments in Ontario.

d) At this time Hydro Ottawa has not adjusted any Transportation Electrification Factor. Through the use of a multi-scenario approach as discussed in a) above, combined with analysis of annual EV sales figures, Hydro Ottawa will continue to compare the multiple Decarbonization scenarios relative to EV sales in Ontario.

e) Hydro Ottawa is not aware of any change to the City's electric bus procurement targets, and the numbers listed are still consistent with OC Transpo's website, accessed July 24th, 2025.[3]

[3] https://www.octranspo.com/en/our-services/vehicles/zero-emission-bus/

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-43

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / pp. 62, 63, 70 (pdf Exhibit 2 part 2, pp. 62, 63, 70)

Preamble:
Hydro Ottawa shows in Figure 5 - 2024 Overall Asset Age Demographics (Current State), that 67% of Metering, 23% of Overhead, 59% of Stations, 26% of Underground and 54% of Overall components have reached or exceeded Typical Useful Life (TUL),

Figure 6 - 2024 Overall Asset Condition Profile (Current State) shows that 12% of the Overhead, 13% of Stations, 3% of Underground and 6% of Overall are currently in poor/very poor condition.

Hydro Ottawa states the “asset renewal strategy does not prioritize replacing assets that have reached or exceeded their TUL. As such, an increase in the frequency of inspections of assets that have reached TUL is also proposed for certain assets.”

QUESTION(S):

a) Explain the disparity between Hydro Ottawa's Asset Age demographics grouped by TUL thresholds shown in Figure 5 and the assessed asset condition profile shown in Figure 6.
    i) Considering the non-correlation between TUL and assessed asset condition for many asset classes, please explain actions being taken by Hydro Ottawa to re-evaluate or re-calibrate TULs to better align its asset age and condition demographics.
b) On page 70 Hydro Ottawa states the “asset renewal strategy does not prioritize replacing assets that have reached or exceeded their TUL.” Is Hydro Ottawa prioritizing replacing assets based

upon condition assessment rather than TUL, or is Hydro Ottawa avoiding investing in assets that have reached or exceeded TUL regardless of their condition assessment?

i) If the latter, has Hydro Ottawa undertaken Cost-Benefit analysis to demonstrate that this is prudent?

c) What is the cost benefit basis for Hydro Ottawa concluding that more frequent inspections are better use of ratepayer money than investing in rehabilitation or maintenance of assets at or beyond TUL that are assessed as being adequate condition?

d) Considering the continued investment in Asset Management, please discuss if the asset renewal strategy is going to be revisited.

RESPONSE(S):

a) Hydro Ottawa's Asset Management Strategy distinguishes between an asset's Typical Useful Life (TUL), which is calendar age, and condition. Condition is determined by various underlying inspection parameters relevant to a given asset type such as age, visual inspections, infrared scanning, electrical testing, load profile, number of operations, failure history, structural aspects etc. TUL is defined for an entire asset type but condition is determined at a single asset level. To this end, there are multiple factors that could impact the condition of individual assets.

Hydro Ottawa’s failure curves and typical useful life update initiative is discussed in Section 4.4.4 under Schedule 2-5-4 - Asset Management Process, which shows the decision taken to update the existing TUL of an asset type or not. An important outcome of this initiative was for Hydro Ottawa’s asset failure records to mature further, to establish more accurate TULs. As indicated in the study, data challenges included “General lack of survival and/or failure data”, "Minimum failure data compared to in-service data” and “Shorter data collection duration compared to the earlier assets’ installation year and the overall study period”. Overall the data was described as low maturity, which Hatch identified as common within the utility sector. To refine the results, where data maturity was low, Hatch produced TUL Adjusted Results. This involved selecting the top 10% of matches that most closely aligned with Hydro Ottawa’s asset registry, while still utilizing Hydro Ottawa data. As Hydro Ottawa continues to accumulate this

data over the next few years it will support potential further TUL adjustments for the relevant asset classes to re-evaluate the relationship with condition, as also suggested by Hatch.

i) Hydro Ottawa aims to recalibrate the TUL of assets by the following means:

- Increasing investments in maintenance programs to capture additional inspection parameters that can drive improvements to the asset condition assessment (ACA) framework and further advance the accuracy of asset condition
- Creating a repository of asset failure data by tracking the age and condition at the time of failure and the nature of replacement (planned, emergency, critical etc)
- Implementing an Enterprise Asset Management (EAM) system to gather asset inspection data, facilitate sophisticated analytics, anomaly/failure identification, and enhanced asset health assessments

b) Hydro Ottawa prioritizes replacing assets based on risk and condition - typical useful life (TUL) is one of the factors in the condition analysis. When evaluating alternatives for asset renewal programs, the impact on the percentage of assets in "degraded condition" or "deteriorated condition" is consistently discussed as a measure of risk mitigation, alongside assets reaching their TUL. Hydro Ottawa also considers the backlog for future asset replacements in its decision making, based on the sheer number of assets reaching their TUL in the near future. In summary, Hydro Ottawa's approach is to prioritize investment based on a risk assessment that heavily weighs asset condition, while also managing the lifecycle of assets reaching or exceeding their TUL to prevent future degraded conditions and associated failure risks.

i) Not applicable, as Hydro Ottawa is not avoiding investing in assets that have reached or exceeded TUL regardless of their condition assessment.

c) Hydro Ottawa has concluded that more frequent inspections are a better investment than immediate rehabilitation or maintenance of assets at or beyond their TUL, but in adequate condition. Hydro Ottawa's previous attempts at refurbishment and rehabilitation, such as cable injections, have had limited success, as detailed in Hydro Ottawa's response to part (a)(i) in interrogatory 2-Staff-104. For the 2026-2030 rate application, Hydro Ottawa's strategy is to

improve the quality of inspection data. This will allow for clearer identification of underlying failure modes and degradation mechanisms, ensuring the selection of appropriate intervention strategies.

For instance, proposed enhancements to the cable testing program will enable the detection of partial discharge issues in cable accessories such as elbows. In such cases, the proper course of action would be to replace the elbows, rather than investing in less effective rehabilitation methods like injections. Therefore, to optimize funding, the initial step involves enhancing inspection data quality to understand and establish failure-cause trends, which will then inform the relevant corrective actions. Hydro Ottawa will also continue to evaluate refurbishment and rehabilitation options, implementing them as needed, based on insights gained from improved inspections.

d) At this time, Hydro Ottawa's asset renewal strategy (focused on asset failure risk mitigation) will guide the strategy for the 2026-2030 period. Hydro Ottawa will continue to advance Asset Management practices (specific to asset renewal strategies) by leveraging additional information collected through inspections within Copperleaf Predictive Analytics (PA) module to refine asset condition and risk. Through these refinements Hydro Ottawa will annually optimize the specific assets planned for replacement. As part of Hydro Ottawa ISO 55000 Certified Asset Management Program, Asset Management Strategies are continuously evaluated for effectiveness and enhancements or adjustments are taken, as necessary.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-44

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / pp. 68-69 (pdf Exhibit 2 part 2, pp. 68-69)

Preamble:
Hydro Ottawa states “the investment required to replace all assets that are projected to be in degraded condition by 2030 is estimated at $862M”. Table 3 provides more detail on the asset renewal needs by condition listing $199M for overhead, $205M for stations, $458M for underground.

QUESTION(S):

a) What is the cost of replacing only the "very poor" condition assets, rather than both "very poor" and "poor"?
b) What were the comparable "very poor" and "poor" percentages represented in Asset System column of Table 3 (i.e., overhead, stations, underground) in the previous application?

RESPONSE(S):

a) It will cost an estimated $266M to only replace assets projected to be in a Very Poor condition by 2030.

b) Asset condition demographics reported during the previous rate application are shown in Table A below. It is important to note that the tables can not be directly compared as Hydro Ottawa has made significant improvements/enhancements to the asset condition assessment (ACA)

framework since 2018, as outlined in Section 4.4.3 of Schedule 2-5-4 - Asset Management Process.

Table A - Percentage of Assets in Poor and Very Poor Condition in 2018

Asset System	% Assets in Poor and Very Poor Condition (2018)
Overhead	21%
Underground	9%
Stations	3%

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-45

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / pp. 72-73, 76 (pdf Exhibit 2 part 2, pp. 72-73, 76)

Preamble:
Hydro Ottawa states that the 2021 national Behind the Meter Survey illustrated that 14% of participants had or would actively take steps to acquire solar panels. Figure 12 - Total System Generator Count 2019-2023 shows that DERs increased ~2% between 2019-2020, ~4% between 2020-2021, 9% between 2021-2022, 8% between 2022-2023, and the total percent increase between 2019 and 2023 is 25.4%. Additionally, Hydro Ottawa states they are “enabling the widespread adoption and utilization of DERs by connecting customers to available financial incentives fostering collaborative partnerships, and implementing strategic programs.”

QUESTION(S):

a) Did the Behind the Meter Survey quantify the time horizon of the individuals interested in acquiring solar panels versus those that had solar panels currently installed?
b) Please explain how Hydro Ottawa has incorporated the Behind the Meter Survey into projections of its customers’ expected behaviour.
c) What is defined as a BESS in Figure 12 (e.g., Residential scale - tens of kWh, Commercial scale - hundreds of kWh, Utility scale - thousands of kWh)?
d) Does the enablement of DER adoption accompany also include revisions to Hydro Ottawa’s technical requirements about DER performance in order to be connected?

RESPONSE(S):

a) Page 25 of Attachment 1-4-1(F) - Behind the Meter Survey outlines the interest in solar panels. While a specific time horizon was not provided, the 14% highlighted in Schedule 2-5-1 - Distribution System Plan Overview is a combination of the following responses:

i) 6% of respondents “Already have/would get this right away”; and

ii) 8% of respondents “Have been/would actively take steps to acquire this”.

b) Customer surveys, including the Behind the Meter survey, are valuable sources of data to support Hydro Ottawa’s planning process. As per Section 2.3.3 of Schedule 2-5-1 - Distribution System Plan Overview, this survey reinforces the need for Hydro Ottawa to modernize its grid to enable more DERs. The specific response percentages from this survey were not incorporated into planning load forecasting as a direct metric, but were used as one of many data points to validate general planning assumptions.

c) The BESS systems, from Figure 12 in Schedule 2-5-1 - Distribution System Plan Overview represent Commercial Scale batteries. These systems are larger, typically ranging from 100 kWh to several MWh, and are designed for commercial or industrial use.

d) With the assumption that “*DER performance”* refers to the technical requirements of the DER, then yes, to support the adoption of DERs Hydro Ottawa has revised or newly created technical requirements, commissioning guidelines and DER service options..

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-46

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 1 / p. 94 (pdf Exhibit 2 part 4, p. 94)
Ref. 2: Exhibit 4 / Tab 1 / Schedule 3 / Attachment C / p. 2 (pdf p. 188)

QUESTION(S):

a) Gross Capital Expenditures in 2026 and 2027 are approximately $50M more than those forecast for 2028 through 2030, resulting in forecast Net Capital Expenditures being higher in 2026 and 2027 compared to 2028 through 2030.
   i) What projects or programs account for the higher expenditures in 2026 and 2027?
   ii) Logistically, how will Hydro Ottawa execute the larger budget, particularly with respect to the current level of employees, as a large portion of the additions to Hydro Ottawa's workforce will not be on board and trained in time to participate in planning or executing the work? (i.e. 131 additional headcount who will be hired by the end of 2026 and 46 more through to end of 2030)
   iii) Please explain why Hydro Ottawa has not levelized the capital expenditures over the forecast period of 2026 through 2030.

RESPONSE(S):

a)
   i) Table A below shows the variance between capital programs when comparing 2026-2027 to 2028-2030. The programs that account for the higher expenditures in 2026 and 2027 are the Fleet Replacement (General Plant), System Expansion (System

Access), Stations & Buildings Infrastructure Renewal (System Renewal) and Capacity Upgrades (System Service).

Table A - Gross Capital Expenditure ($'000 000s)

Investment Category	Capital Program	Capital Spending		
		2026-2027 Average	2028-2030 Average	Variance
General Plant	CCRA	$ 9,647	$ 8,855	$ 792
	Fleet Replacement	$ 13,153	$ 4,763	$ 8,390
	Tools Replacement	$ 900	$ 1,026	$ (125)
	Buildings - Facilities	$ 1,451	$ 1,217	$ 234
	Grid Technologies	$ 989	$ 773	$ 217
	Meter to Cash	$ 651	$ 2,516	$ (1,865)
	Customer Engagement Platform	$ 780	$ 320	$ 460
	Enterprise Solutions	$ 158	$ 371	$ (213)
	Infrastructure and Cybersecurity	$ 2,524	$ 3,440	$ (916)
	Data and System Integrations	$ 700	$ 694	$ 6
Total		$ 30,954	$ 23,974	$ 6,980
System Access	Plant Relocation	$ 6,656	$ 7,215	$ (559)
	System Expansion	$ 33,144	$ 14,843	$ 18,300
	Customer Connections	$ 41,578	$ 44,867	$ (3,289)
	Generation Connections	$ 724	$ 931	$ (207)
	Metering	$ 327	$ 357	$ (29)
Total		$ 82,430	$ 68,213	$ 14,217
System Renewal	Stations & Bldgs Infra Renewal	$ 24,392	$ 19,624	$ 4,768
	OH Distribution Asset Renewal	$ 12,927	$ 13,982	$ (1,055)
	UG Distribution Assets Renewal	$ 19,386	$ 21,421	$ (2,035)
	Corrective Renewal	$ 12,660	$ 13,843	$ (1,183)
	Metering Renewal	$ 15,007	$ 18,784	$ (3,777)
Total		$ 84,372	$ 87,653	$ (3,281)
System Service	Capacity Upgrades	$ 87,588	$ 57,238	$ 30,350
	Stations Enhancements	$ 552	$ 649	$ (97)

Investment Category	Capital Program	Capital Spending		
		2026-2027 Average	2028-2030 Average	Variance
	Distribution Enhancements	$ 18,480	$ 18,609	$ (128)
	Grid Technologies	$ 535	$ 1,779	$ (1,244)
	Control and Optimization	$ 1,224	$ 380	$ 844
	Field Area Network	$ 3,914	$ 4,307	$ (393)
Total		$ 112,294	$ 82,961	$ 29,332
Grand Total		**$ 310,050**	**$ 262,802**	**$ 47,248**

ii) Hydro Ottawa's strategy for managing an increased program volume is rooted in a blend of strategic, timely hiring and a consistent approach to contracting, designed to meet the demands of the proposed increases beginning in 2026. In 2024, Hydro Ottawa added 50 key positions to address immediate needs while preparing for the increased workload expected in 2026. Of these, 42 positions were allocated to Engineering & Design, Metering, and Distribution Operations to support immediate drivers such as customer connection and capacity growth, DER and capacity request complexity, grid modernization, and enhanced leadership. These hires inherently support ongoing volume increases by contributing to the planning, preparation, design and construction phases of projects, allowing the utility to be fully prepared and ready to execute in 2026. Hydro Ottawa's execution strategy also consistently uses contracted resources to manage seasonal and programmatic volume fluctuations. Additionally, temporary employment arrangements are leveraged to augment internal capabilities. This approach maintains an internal headcount commensurate with the lowest consistent workload on both an annual and long-term basis, as described in Section 3.1.2.1 of Attachment 4-1-3(C) - Workforce Growth.

It is also important to note that when considering the logistics of execution by Investment Category, increases in capital expenditure are not linearly associated with addition of entire positions. For System Renewal, while AMI 2.0 efforts require incremental positions for implementation and maintenance, large portions of this program will be outsourced.

In System Service, Capacity Upgrade capital expenditure for new substations demands multi-million dollar increases in equipment spending and civil construction, both performed by third-party vendors and contractors. For the CCRA program under General Plant, the level of Hydro Ottawa's workforce does not affect this category, as the increased investment represents payment to Hydro One for transmission service correlating with the completion of System Service projects.

iii) Capital expenditures have been levelized where feasible for programs within Hydro Ottawa's control, namely programs within System Renewal and subsets of programs within System Service. Capacity and customer-driven projects are instead driven by load forecast and customer specific requirements and timelines. Furthermore, long lead times for major equipment and specific project milestones associated with customer driven projects and capacity projects often necessitate non-levelized expenditures in these areas. In the General Plant investment category, expenditures such as Fleet additions are higher in the beginning portion of the rate time to coincide with the additional headcount. Ultimately, Hydro Ottawa's expenditures are strategically executed to meet its project and program deliverables as set out in the Distribution System Plan (DSP).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-47

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / p. 29 (pdf Exhibit 2 part 2, p. 191)

QUESTION(S):

a) How did Hydro Ottawa establish the target of 0% for this FARC% KPI?
b) In regard to Table 17 – System Losses, how does Hydro Ottawa differentiate between technical and non-technical losses?
c) What is Hydro Ottawa's estimate of non-technical losses as a percentage of total losses?
d) Please provide a revised Table 17 showing technical and non-technical losses on separate lines.

RESPONSE(S):

a) In its 2021-2025 Rate Application, Hydro Ottawa's target for the FARC% KPI was set to 0% to ensure that all feeder load can be supplied even under a contingency scenario, as detailed in section 3.4.2.2 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement. This strategy ensures feeder assets remain within thermal limits and identifies network constraints, guaranteeing a safe and reliable power supply for customers.

b) Hydro Ottawa does not differentiate between technical and non-technical losses in its reporting or calculations and both form part of the Table 17 - System Losses. The losses are based on

electricity purchases and sales as presented in Table 1 - Losses as a Percentage of Higher Value Purchases for the Previous Five Years in Schedule 8-2-3 - Loss Adjustment Factors.

c) As Hydro Ottawa does not differentiate between technical and non-technical losses in its reporting or calculations, it does not have a specific estimate for non-technical losses as a percentage of total losses. System losses are reported as combined.

d) As Hydro Ottawa does not differentiate between technical and non-technical losses in its reporting or calculations, a revised Table 17 cannot be provided to show technical and non-technical losses on separate lines.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-48

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / p. 34 (pdf Exhibit 2 part 2, p. 196)

QUESTION(S):

a) Given that Hydro Ottawa's SAIFI performance trend excluding Loss of Supply and Major Event Days (MED) has improved from 2014 to 2023, please explain how the proposed significant increase in capital spending to improve reliability can be justified.
b) Please provide a revised Figure 5 showing the SAIFI results for 2013 and 2024 excluding Loss of Supply and Major Event Days.

RESPONSE(S):

a) While SAIFI performance (excluding Loss of Supply and Major Event Days) has improved, this metric alone does not fully encompass the complex challenges and future demands facing the distribution system. The significant capital expenditure plan for 2026-2030 is justified by several critical factors beyond historical SAIFI performance as described in Section 2.3 of Schedule 2-5-1 - Distribution System Plan Overview:

- **Aging Infrastructure Requires Proactive Renewal:** A substantial portion of the grid consists of assets that have met or exceeded their typical useful life (TUL), posing significant safety, reliability and environmental risks. Hydro Ottawa prioritizes proactive replacement over reactive repairs for degraded assets to prevent unplanned outages and costly emergency interventions. A key investment priority is to mitigate failure risk by strategically upgrading or replacing deteriorating and critical infrastructure, prioritizing assets with the

greatest impact on system reliability and safety based on condition assessments. As outlined in Table 3 under Schedule 2-5-1: Distribution System Plan Overview, the estimated investment to replace all assets projected to be in degraded condition by 2030 is $862M, which would effectively reduce the percentage of degraded assets to 0%. However, competing financial priorities—notably growth, electrification, grid modernization, and resilience—make this investment level impractical. Despite the projected increase in degraded assets, Hydro Ottawa proposes a $261M investment over the 2026-2030 period to maintain its current level of service reliability through improved risk prioritization, predictive analytics, and enhanced inspection and maintenance programs, ensuring intervention on the most critical assets impacting reliability.

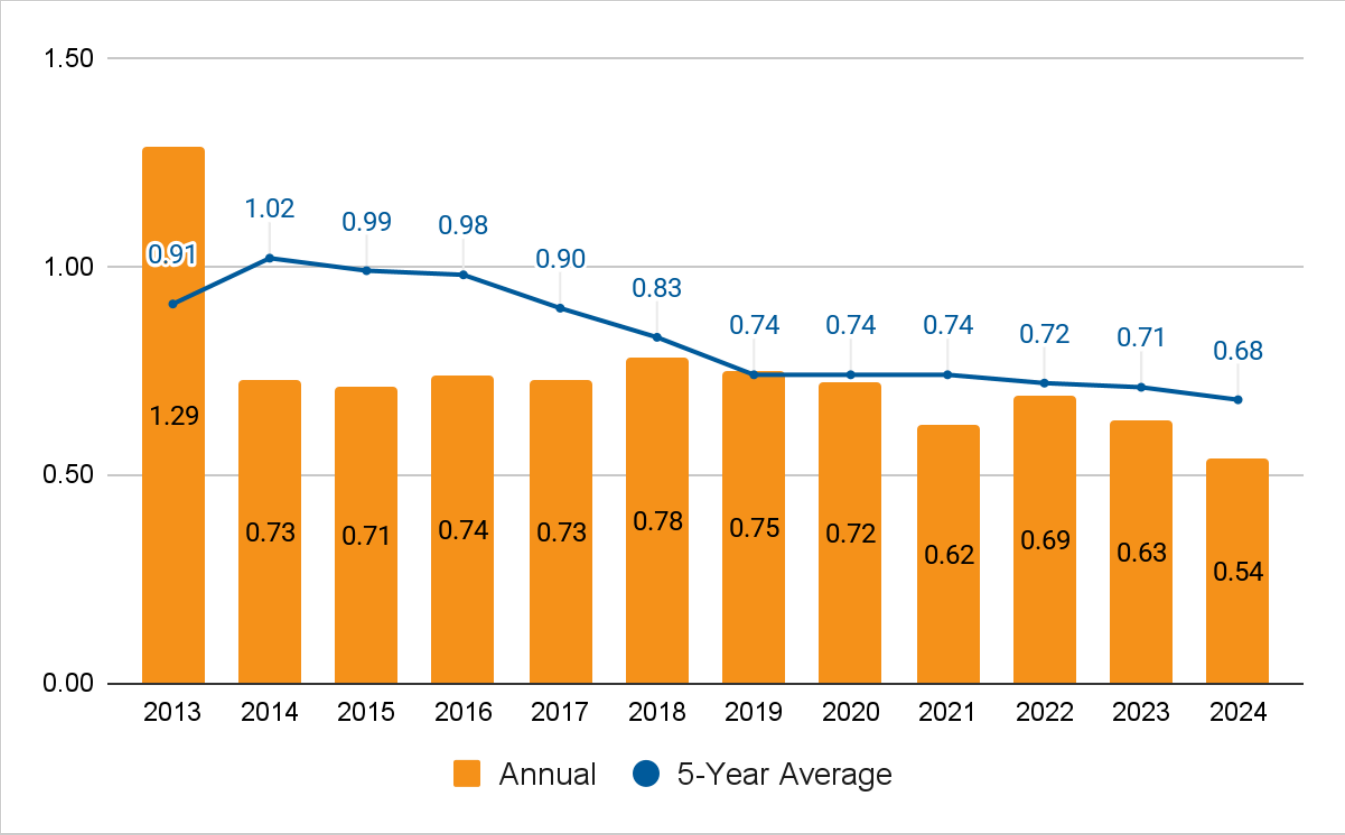
- **Increasing Extreme Weather Events Demand Enhanced Resilience:** Ottawa has experienced an increasing frequency and intensity of severe weather events, such as the Derecho storm of 2022, which significantly impacted the system. The plan incorporates climate risk mitigation strategies, including strategic undergrounding and system hardening of vulnerable infrastructure, reconfiguring networks, and enhancing vegetation management (tree trimming), to improve grid resilience and service reliability.
- **Rapid Growth and Electrification Necessitate Capacity Expansion:** The City of Ottawa is experiencing strong economic and population growth, leading to a significant increase in electricity demand. Electrification of heating and transportation (EVs, heat pumps, light rail transit) is projected to increase demand, requiring capacity expansion of substations, transformers, and lines, and expanded connections with provincial transmission lines. These capacity investments are therefore critical to ensuring Hydro Ottawa can meet the growing demand and continue to provide reliable electricity to the community
- **Grid Modernization for Future Capabilities:** Critical investments are needed to accelerate digital transformation, enhance grid observability and control, and enable the integration of distributed energy resources (DERs) and smart technologies. The plan includes incremental investments for enhanced observability through System Renewal programs, such as replacing manual overhead and underground switches with remote operable switches at targeted locations, which will improve system observability and control for better outage response.

- **Investing in the Workforce to Meet Demands:** Meeting these growing demands requires significant investment in Hydro Ottawa's workforce, and the continued use of contractors to meet construction, maintenance, and other needs, which requires efficient management and skilled performance. Maintaining the safety and operational efficiency of trades personnel tools and equipment is a priority for the workforce. Customers also expressed the need for knowledgeable staff and efficient processes in customer service.

In summary, while past SAIFI performance demonstrates effective management of the existing system, the proposed investments are a forward-looking imperative. They are designed to proactively manage the escalating risks from aging infrastructure, the increasing impact of severe weather, the unprecedented demands of growth and electrification, and the need for a modernized, resilient grid and a skilled workforce. This approach ensures continued delivery of safe, reliable, and sustainable electricity to the growing community for decades to come.

b) Figure A below is a revised Figure 5 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement, presenting the SAIFI results for 2013 to 2024, excluding Loss of Supply and Major Event Days. Hydro Ottawa's reliability performance, as measured by SAIFI, shows this downward trend from 2014 through 2023, and this trend of stable improvement has continued through 2024. However, maintaining this stable improvement in reliability is challenged by increasingly severe weather events and a growing proportion of degraded assets beyond their TUL, as detailed in Section 2.3.2 of Schedule 2-5-1. Therefore, planned increases in capital and renewal investments are a direct response, essential for modernizing and strengthening the grid to sustain and enhance performance against these escalating risks.

Figure A - SAIFI excluding Loss of Supply and Major Event Days (2013-2024)



INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-49

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / pp. 36-37 (pdf Exhibit 2 part 2, pp. 198-199)

Preamble:
Hydro Ottawa states that “in 2022 and 2023, SAIDI exceeded the five-year average target by 0.14 and 0.17, with 3% of outages being responsible for 48% of SAIDI. This was due to several factors, including delays in making areas safe, increased adverse weather events, need for additional fault locating equipment and resources, tree contact, and foreign interference.”

QUESTION(S):

a) Please show the contribution of tree contact and foreign interference to the 2022 and 2023 SAIDI results, both including and excluding Loss of Supply and Major Event Days.
b) Confirm that the SAIDI trend has been stable or improving since 2014.
c) Please explain why, in Figure 7 – SAIDI Loss of Supply and Major Event Days, the 5-year average increased from 2014 to 2018 despite generally improving annual results over this period.
d) If the reason is that much better results were experienced in 2010 and 2011, please provide the annual results for 2010-2013.

RESPONSE(S):

a) The following tables provide the SAIDI contribution, in customer hours, from the Tree Contact and Foreign Interference cause categories for 2022 and 2023. The contribution, excluding LoS

and MED for 2022 and 2023, is derived from Table 25 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement.

Table A - 2022 Values

Cause Category	SAIDI (Including LoS and MED)	SAIDI (Excluding LoS and MED)
Tree Contact	218,941	74,967
Foreign Interference	199,978	54,714

Table B - 2023 Values

Cause Category	SAIDI Contribution (Including LoS and MED)	SAIDI Contribution (Excluding LoS and MED)
Tree Contact	130,784	47,158
Foreign Interference	153,016	77,856

b) Refer to Schedule 2-5-3 - Performance Measurement for Continuous Improvement. The downward trend of the 5-year Average noted in figure 7 of Section 4.2 confirms that Hydro Ottawa's SAIDI performance has been stable or improving since 2014.

c) The 5-year average for SAIDI increased because the strong performance from 2009 and 2010 were no longer part of the calculation. As those stronger years were dropped from the rolling average, they were replaced by subsequent years with higher SAIDI values, causing the overall average to rise.

d) While the original question specified the years 2010 and 2011, this response identifies 2009 and 2010 as the years when significantly better results were achieved. Table C below shows the annual SAIDI results from 2009 to 2013.

Table C - 2009-2013 SAIDI Annual Results

Year	2009	2010	2011	2012	2013
SAIDI	0.82	0.74	1.13	1.07	1.42

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-50

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / pp. 38-39 (pdf Exhibit 2 part 2, pp. 200-201)

Preamble:
Hydro Ottawa states that "Hydro Ottawa uses a Feeder Performance Index (FPI) to assess the condition of its electricity distribution feeders." Table 21 – Worst Feeder Analysis shows that there were 5 feeders in 2019, 8 feeders in 2020, 6 feeders in 2021, 7 feeders in 2022 and 6 feeders in 2023 that were considered the worst performing.

QUESTION(S):

a) Please provide the formula used to calculate FPI.
b) Please list all feeders that were identified as Worst Feeders in three or more years from 2019 to 2023 and explain the primary causes of poor performance for each of these chronically worst performing feeders.

RESPONSE(S):

a) Hydro Ottawa calculates the Feeder Performance Index (FPI) per feeder using the below formula:

$$Total\ Score = \left(\frac{\sum_{i=1} Weight_i \times Ranking_i}{16}\right) \times 100$$

Each criteria is weighted, with outage frequency at 1, customer impact at 1, and outage duration at 2. Each criteria is then ranked based on its performance over a 12-month period compared to their five year performance average, excluding Major Event Days, Loss of Supply and Scheduled outages. Please see the table below, which defines the limits used for the FPI rank scores as per Hydro Ottawa standards.

Table A - FPI Criterion Score Limits

Criteria Rank	Criteria Score	Limits
A	4	< 5 year average of the 50th Percentile Result
B	3	>= 5 year average of the 50th Percentile Result and < 5 year average of the Mean Average Result
C	2	>= 5 year average of the Mean Average Result and < 5 year average of the 95th percentile result
D	1	>= 5 year average of the 95th percentile result and < 5 year average of the 99th percentile result
E	0	>= 5 year average of the 99th percentile result

For example, circuit JKGF4 in 2019 was ranked C (2) for outage frequency, D (1) for customer impact, and E (0) for outage duration. To calculate the Feeder Performance Index (FPI), weights are applied to the respective criteria and the FPI score is calculated as follows:

$$FPI = \left(\frac{(2\,x\,1) + (1\,x\,1) + (0\,x\,2)}{16}\right) x\,100$$

The final FPI score is 18.75, which is considered "very poor" as described in Table 20 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement.

b) Based on Table 21 - Worst Feeder Analysis of Schedule 2-5-3 - Performance Measurement for Continuous Improvement, a chronological list of the feeders identified as Worst Feeders in three or more years from 2019 to 2023, along with the primary causes for their chronic poor performance, is presented in the list below:

- JKGF4: This feeder had occurrences in 2019, 2020, and 2021. The primary causes were Foreign Interference (Cause Code 9) and Tree Contacts (Cause Code 3).
- 77M1: This feeder had occurrences in 2021, 2022, and 2023. The primary cause was Equipment Failure (Cause Code 5).
- 77M6: This feeder had occurrences from 2019 to 2023. The primary cause was Equipment Failure (Cause Code 5).

Definitions of cause codes can be found in Table 24 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-51

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / pp. 44-45 (pdf Exhibit 2 part 2, pp. 206-207)

Preamble:
Table 24 - OEB Definition of Cause Codes lists 3 – Tree Contacts as the following: “Interruption caused by faults resulting from tree contact with energized circuits except for the interruptions under the conditions described under cause code 6.” Hydro Ottawa also provides Table 25 - Five-Year SAIFI and SAIDI Contribution by Outage Type (Excluding MED’s).

QUESTION(S):

a) Regarding Table 24 – OEB Definition of Cause Codes, please confirm that interruptions caused by trees falling on lines or structures during events classified under cause code 6 are not recorded by Hydro Ottawa as tree contacts.
   i) If confirmed, please indicate whether Hydro Ottawa attempts to determine and track the proportion of cause code 6 interruptions that are caused by tree contacts rather than direct pole failures absent tree contacts.
   ii) If Hydro Ottawa does not track the proportion of interruptions caused by tree contacts during cause code 6 events, please explain how Hydro Ottawa is able to determine whether the most effective strategy to mitigate future cause code 6 interruptions would be more aggressive vegetation management or replacing wood poles assessed as being in poor condition.

b) Regarding Table 25 - Five-Year SAIFI and SAIDI Contribution by Outage Type (Excluding MED’s), please provide a revised Table that includes Major Event Days.

RESPONSE(S):

a) Regarding Table 24 – OEB Definition of Cause Codes, interruptions caused by trees falling on lines or structures during events classified under cause code 6 are not recorded by Hydro Ottawa as tree contacts as the primary cause, they are classified under Adverse Weather events.

   i) Hydro Ottawa identifies and records secondary causes of interruptions, therefore interruptions caused by tree contact that occur during events classified under Adverse Weather would be tracked.

   ii) As per the response in part (i), Hydro Ottawa does track the proportion of interruptions caused by tree contacts during cause code 6.

b) Please see Table A - Five-Year SAIFI and SAIDI Contribution by Outage Type, which includes Major Event Days below.

Table A: Five-Year SAIFI and SAIDI Contribution by Outage Type (Including MED's)

Code - Cause	SAIFI & SAIDI Contribution	2019	2020	2021	2022	2023
0 - Unknown	Number of Interruptions	66	53	28	38	66
	Customer Interruptions	31,473	33,536	10,420	23,940	20,721
	Customer-Hours	25,666	20,163	9,138	35,959	23,185
1 - Scheduled Outages	Number of Interruptions	647	755	742	618	570
	Customer Interruptions	13,668	22,522	17,058	21,173	38,571
	Customer-Hours	34,899	49,218	59,325	47,286	97,117
2 - Loss of Supply	Number of Interruptions	29	27	35	40	77
	Customer Interruptions	84,734	73,945	115,354	218,821	158,144
	Customer-Hours	126,600	99,571	66,352	142,147	73,966
3 - Tree Contact	Number of Interruptions	76	104	83	104	105
	Customer Interruptions	45,788	18,548	21,474	45,667	35,214
	Customer-Hours	67,655	30,671	30,386	76,794	56,818
4 - Lightning	Number of Interruptions	26	27	18	9	32
	Customer Interruptions	27,749	12,188	20,275	7,008	31,224
	Customer-Hours	10,273	6,797	47,209	3,812	40,417
5 - Equipment Failure	Number of Interruptions	269	269	249	210	169
	Customer Interruptions	65,446	115,479	65,945	100,784	52,484
	Customer-Hours	81,989	306,002	97,196	144,967	115,889
6 - Adverse Weather	Number of Interruptions	16	6	11	64	167
	Customer Interruptions	4,326	1,393	10,706	226,599	128,041
	Customer-Hours	5,344	4,750	7,511	13,540,805	1,986,652
7 - Adverse Environment	Number of Interruptions	14	4	9	4	2
	Customer Interruptions	1,710	197	8,740	287	1,243
	Customer-Hours	4,850	475	9,754	652	2,436
8 - Human Element	Number of Interruptions	23	9	17	14	14
	Customer Interruptions	33,391	8,267	19,019	11,109	28,727
	Customer-Hours	16,452	1,508	13,139	3,720	33,600
9 - Foreign Interference	Number of Interruptions	211	178	153	114	177
	Customer Interruptions	56,741	55,968	53,398	38,540	42,276
	Customer-Hours	64,742	65,977	48,943	57,831	79,050

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-52

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / p. 53 (pdf Exhibit 2 part 2, p. 215)

QUESTION(S):

a) Hydro Ottawa provides Figure 15 which "shows equipment failure trends over the last five years with respect to the number of interruptions, number of customers interrupted and customer interruption hours." Please explain the reasons for the increasing trend in Customer Hours illustrated in Figure 15.

RESPONSE(S):

a) The increasing trend in customer hours shown on the Equipment Failure Historical Trend in Figure 15 is mainly due to a significant increase in restoration time in 2022 for outages consisting of overhead asset failures such as recloser flashovers, pole fires from insulation failure, blown potheads and broken insulators. Restoration times for these outages were prolonged as extra time was required to make the outage location safe while coordinating with the City of Ottawa and Emergency Services in addition to performing forced switching and sectionalizing during fire related emergencies. As noted in Section 5 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement, Hydro Ottawa has observed and considered this while analyzing the factors impacting SAIDI, and has proposed investments for continuous improvement.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-53

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / pp. 58-59 (pdf Exhibit 2 part 2, pp. 220-221)

Preamble:
Hydro Ottawa states that Figure 17 – Adverse Weather Historical Trend "provides a visual representation of the trend in outages caused by adverse weather over the past five years." Hydro Ottawa also states that "Outages attributed to adverse weather have been on the rise over the past five years."

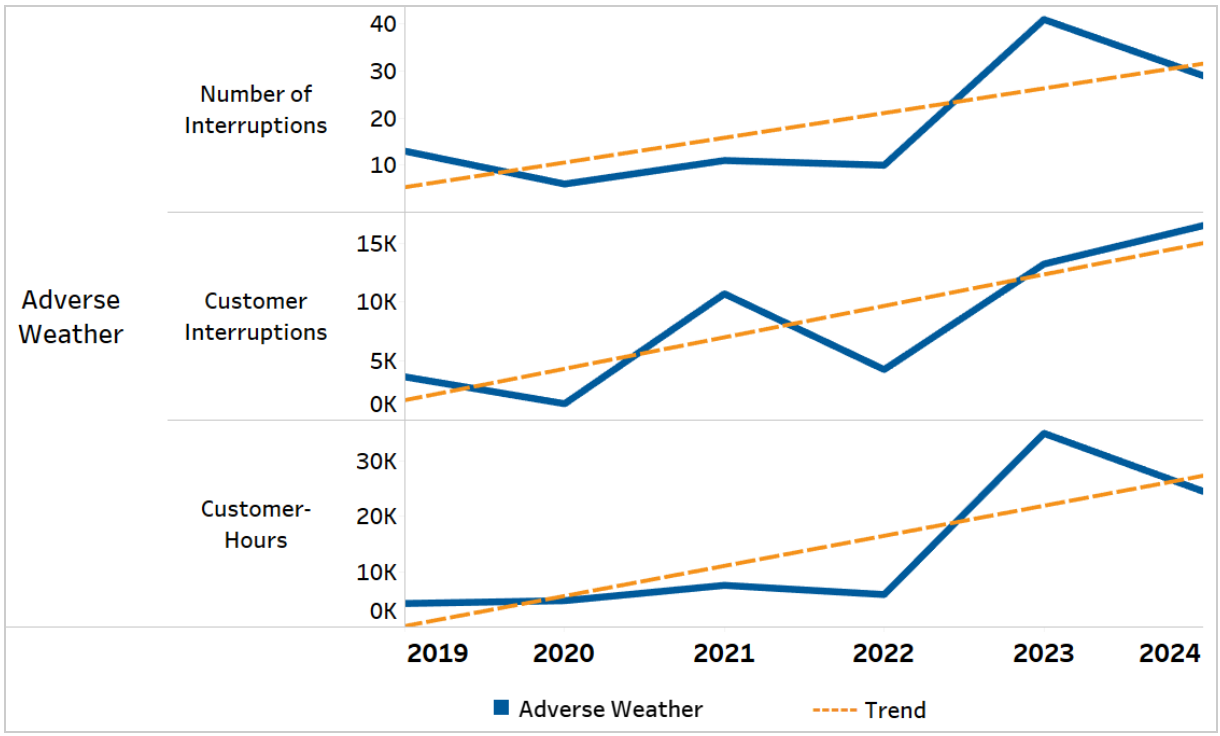
QUESTION(S):

a) Please update Figure 17 to include 2024 values.
b) The increased outage trend appears to primarily derive from the performance in 2023, prior to which these trends were relatively flat. Discuss if one bad year creates a trend that justifies significant capital spending increases.
c) Please explain how the trends depicted in Figure 17 relate to the data that appears in Figure 8.
d) Has Hydro Ottawa used data from Figure 17 to replicate figures it has presented in other parts of the filing, including Figure 17?
    a) If yes, please provide the materials.
    b) If no, please discuss why not.

RESPONSE(S):

a) Please see below Figure A - Adverse Weather Historical Trend, which has been updated to include 2024 values.

Figure A - Adverse Weather Historical Trend (including 2024)



b) Figure 17, "Adverse Weather Historical Trend" as noted in Reference 1, shows a significant increase in outages in 2023 due to adverse weather. This is not an anomaly, as the 2024 data (updated in part (a) of this interrogatory) indicates a continuation of this upward trend. The outages due to Adverse Weather metric reinforces an existing, escalating trend in severe weather events, as detailed in Section 6.4 and Section 5.2.2.4 of Schedule 2-5-4 - Asset Management Process. From 2019 to 2023, 12 major event days significantly impacted Hydro Ottawa's service territory, driven by changing weather patterns as discussed in Section 4.4 of Schedule 2-5-3 - Performance Measurement for Continuous Improvement. Additional critical factors beyond reliability performance that necessitate increased capital spending are also outlined in part (a) of Hydro Ottawa's response to interrogatory 2-Staff-48. In response to these escalating trends, increased spending has been a focus of Hydro Ottawa's Distribution System Plan, specifically through Section 2.3.4 Enhancing Resilience and Section 3 Distribution Enhancement of Schedule 2-5-8 System Service Investments, to ensure sustained and strategic investment in infrastructure resilience.

c) Figure 17 noted in Reference 1 presents outage information aligned with the OEB's "Adverse Weather" cause code definition for reliability reporting, while Figure 8 corresponds to the IEEE Standard 1366 approach for identifying Major Event Days (MEDs). Both figures are consistent with the OEB's electricity Reporting and Recordkeeping Requirements (RRR).

d) The data in Figure 17 noted in Reference 1, representing outages due to adverse weather, is distinct and not replicated for other primary cause trends. However, this unique data is included in the reporting of annual reliability statistics.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-54

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 3 / p. 68 (pdf Exhibit 2 part 2, p. 230)

Preamble:
When analyzing the factors impacting SAIDI, Hydro Ottawa stats it observed:

- Delays in making the outage area safe;
- Increase in adverse weather events requiring increased patrolling and safety measures prior to restoration;
- Need for more fault locating equipment and SCADA switches;
- Tree contact due to deteriorating vegetation outside of the regular trim zones;
- Foreign interference due to motor vehicle accidents and failure of customer owned equipment causing delays in restoration due to the coordination involved.

QUESTION(S):

a) Please identify which of the listed factors can be most effectively mitigated by additional capital spending and explain how additional spending will mitigate each factor.

RESPONSE(S):

a) Hydro Ottawa proposes capital investments in the Distribution Enhancements program to further reduce outage restoration times. These investments aim to improve the speed and efficiency of outage restoration by equipping System Operators with additional tools and options, thereby enhancing system visibility and increasing overall grid resilience. A summary of the initiatives proposed by Hydro Ottawa towards reducing outage restoration times and the intended benefits

are listed in Section 5 Continuous Improvement of Schedule 2-5-3 - Performance Measurement for Continuous Improvement, mainly through investments in the distribution enhancements program. Further details on Hydro Ottawa's distribution enhancements program are available in Section 3 of Schedule 2-5-8 - System Service Investments.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-55

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 1-3 (pdf Exhibit 2 Part 2, pp. 1-3)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 4 / p. 38 (pdf Exhibit 2 Part 2, p. 38)
Ref. 3: Exhibit 4 / Tab 1 / Schedule 1 / p. 2 (pdf p. 2)

Preamble:
The application's Asset Management Process mentions Hydro Ottawa's Asset Management System, which ensures methodical asset management, aligning expenditures with four Investment Priorities: growth and electrification, renewing deteriorating infrastructure, grid modernization, and enhancing resilience. The Asset Management Process section describes the construction of new stations, targeted upgrades and the implementation of Non-Wires Solutions to address immediate capacity constraints.

Hydro Ottawa also mentions creating a comprehensive distribution asset model within the Copperleaf Asset Predictive Analytics (PA) module. It is mentioned that Copperleaf is an asset investment planning and management software solution that supports strategic asset planning and budgeting decisions.

Hydro Ottawa is seeking approval for $140M in OM&A funding in the 2026 test year and expects this level of funding to enable it to meet a variety of needs, including addressing maintenance needs, accommodating customer growth, and additional workforce to execute the capital program in the DSP and ongoing maintenance.

QUESTION(S):

a) Please categorize and rank all planned system investments by priority, considering system needs, reliability, avoiding/deferring costs, and/or any other factors. This ranking should list all individual investments and specify which factors were emphasized. Please provide rankings within each Investment Category (e.g., System Access, System Service) as well as for the overall DSP.

b) Of the NWSs proposed, please categorize and rank all planned NWS initiatives by priority. This ranking should list all individual NWS programs (e.g. NWSCP – Save on Energy Retrofit Adder Program, NWSCP – Residential Demand Response, BESS in West 28 kV system, BESS in Bells Corners/ Bayshore 8 kV system), including those proposed as Capital Expenditures as well as OM&A expenses.

c) Please categorize and rank all planned OM&A spending/programs by priority.

d) Please file the output of the Copperleaf Asset Predictive Analytics for Hydro Ottawa's 2026-2030 strategic asset planning and budgeting decision.

e) Please provide all limits used in Copperleaf for the overall budget, budget categories, or other types of limits.

f) What percentage of investments were forced (i.e. deemed mandatory) investments? What percentage of expenditures is due to forced projects?

RESPONSE(S):

a) Hydro Ottawa notes that Predictive Analytics (Ref 2) is used to forecast capital requirements for programs within System Renewal, not for the entire portfolio of planned system investments. For questions concerning all planned system investments, the correct reference is Section 3.1 of Schedule 2-5-4 - Asset Management Process, which details the Business Planning Process and the overall Capital Expenditure Plan. As part of the Business Planning Process, Hydro Ottawa does not rank and prioritize all planned system investments individually in the manner requested. The investment strategy is instead guided by a comprehensive and multi-layered process that balances adherence to the four investment priorities (Growth & Electrification, Renewing Deteriorating Infrastructure, Grid Modernization and Enhancing Grid Resilience) with cost-effectiveness and affordability for customers.

The process that Hydro Ottawa followed to finalize the Capital Expenditure Plan is outlined in part (b) of the response to interrogatory 2-Staff-73.

b) The Non-Wires Customer Solutions Programs and the BESS were not prioritized against one another as part of the Business Planning Process however, they have been ranked within their respective programs below.

Non-Wires Customer Solutions Program (NWCSP): This portfolio of programs will be deployed to provide capacity and reliability support in targeted areas by providing customers with opportunities to participate in a variety of programs aimed to reduce peak demand. Within this rate filing, the areas in which the NWCSP will be deployed have immediate needs (refer to response (a)(i) and (a)(ii) within interrogatory 2-Staff-67), and thus the portfolio and the programs within it are considered high priority for deployment. Table A below lists the six programs within the portfolio and their priority (refer to the response to interrogatory 2-Staff-67 for the explanation leading to the selection of six programs, instead of the originally identified four). Table A also includes additional context contributing to the selection of the programming.

Table A - Non-Wires Customer Solutions Program Priority and Selection Criteria

Program	Priority	Criteria

Commercial Retrofit Adder Program	High	• IESO currently operates Retrofit Program within Save On Energy
		• History of successful collaboration with IESO
		  ○ Kanata North Retrofit+ program operated in the targeted area previously[1]
		• Mature program process
		  ○ Application platform, participant agreements already in place
		  ○ Regional Retrofit Adders already in place[2]
		  ○ Program Measurement & Verification (M&V) process already in place (IESO led)

Residential Demand Response Program	High	• IESO currently operates Peak Perks that presents an opportunity for cost savings through collaboration if feasible • Controllable devices previously installed as part Smart Thermostat Local Program in targeted area[3]
Commercial Demand Response (HVAC) Program	High	• Toronto Hydro operates a successful, mature program already in Ontario that can be quickly replicated[4] • IESO does plan to launch a Commercial HVAC DR Program[5] in 2026 that presents an opportunity for cost savings through collaboration if feasible
Residential Solar and Battery Storage Adder Program	High	• IESO (with Enbridge) currently operates Home Renovation Savings Program within Save On Energy • Although this Save On Energy program is new, program process exists ○ Application platform, participant agreements exist

Commercial Solar Adder Program	High	• IESO operates Retrofit Program within Save On Energy (Solar PV is a measure within the program)
		• History of successful collaboration with IESO
		  ○ Ottawa Large Solar DER measure pilot[6]
		• Mature program process
		  ○ Application platform, participant agreements already in place
		  ○ M&V process already in place (IESO led)

Commercial Battery Storage Program	High	• Strong potential for high, long-term value to local distribution system

[1] https://ieso.ca/-/media/Files/IESO/Document-Library/conservation/EMV/2022/PY2022-IF-HOL-Kanata-North-Evaluation-Report.pdf
[2] https://www.saveonenergy.ca/For-Business-and-Industry/Programs-and-incentives/Local-Initiatives#regionaladders
[3] https://ieso.ca/-/media/Files/IESO/Document-Library/conservation/EMV/2021/PY2021IF-HOL-Smart-T-Evaluation-Report.pdf
[4] https://www.ieso.ca/-/media/Files/IESO/Document-Library/funding/Grid-Innovation-Fund/Toronto-Hydro-project-brief.pdf and https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20220913-toronto-hydro-local-dr-pilot.pdf
[5] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/eDSM/eDSM-Framework-20250624-presentation.pdf
[6] Refer to Section 2.4.3 of Schedule 1-4-1 - Customer Engagement Ongoing, p. 39

Utility-Owned Battery Energy Storage Systems (BESS)

Hydro Ottawa plans to deploy utility-owned BESS across four regions between 2026 and 2030. These deployments are strategically located in constrained regions where planning capacity is projected to be exceeded in the 2026 - 2030 period. The BESS will be utilized for peak load management and reliability benefits. For details on the capacity utilization of each BESS installation, see Section 2.1, page 8, of Schedule 2-5-8 - System Service Investments. For details on the specific region and how capacity needs were determined, see Section 2.3.2.3 of Schedule 2-5-8 - System Service Investments.

All four BESS have been categorized as high priority and the energization dates for the specific deployments have been staggered based on the timing of the needs identified, as described within Table B.

Table B - Utility Owned BESS Priority Ranking Criteria

Utility Owned BESS	Priority	Criteria
2.5 MW at Beckwith DS (2028)	High	• Beckwith peak load is above planning capacity • Limited inter-station transfer capability • Wire alternatives would require costly transmission upgrades
5 MW at Casselman DS (2028)	High	• Casselman peak load will surpass planning capacity by 2030 • No inter-station transfer capability • Wire alternatives would require costly transmission upgrades
7 MW in the Bells Corners/ Bayshore (2029)	High	• Bayshore and QCH stations in the Bells Corners/ Bayshore region will surpass planning capacity by 2030 • Inter-station transfer capability available in the short term • Wire alternatives would require costly transmission upgrades
10 MW in the Core 13kV and West 13kV (2030)	High	• All stations will surpass planning capacity by 2028 • Inter-station transfer capability available in the short term • Wire alternatives are planned beyond 2030 (conversion of Bronson to 13kV) • Support required from NWS in the interim and will also support in the long term (beyond 2030) given growth in the Downtown Core and the constrained 115kV transmission system

c) As noted in the Business Plan Process referenced in part (a), Hydro Ottawa did not categorize and rank all OM&A investments by individual priority. Details of the process followed to develop the OM&A budget are provided in 2-Staff-73b.

d) Hydro Ottawa would like to clarify that the output of Predictive Analytics does not inform the entire Capital Expenditure Plan, as described in response to part (a). Predictive Analytics is used to inform System Renewal asset replacement strategies, along with additional factors like system observability, capacity, and reliability considered separately for finalizing the preferred alternative.

It is unclear what staff is requesting as the volume of the data requested is extensive and depending on the output, selected comprises highly sensitive data and large quantities, for example 10 tabs with nearly 1,000,000 rows and 40 columns. As a result Hydro Ottawa is unclear in what is being requested as providing this level of data appears to be outside the scope of the application.

e) Hydro Ottawa would again like to clarify that the output of Predictive Analytics does not inform the entire Capital Expenditure Plan, as described in response to part (a). Predictive Analytics is used to inform System Renewal asset replacement strategies.

In its initial 2026-2030 budgeting process, Hydro Ottawa did not set a high-level capital spending target. This led to Copperleaf PA recommending asset interventions totaling $862 million (representing only a portion of capital expenditures), as detailed in Table 3 on page 69 of Schedule 2-5-1 - DIstribution System Plan Overview. Hydro Ottawa later established a corporate capital expenditure plan target of $1.2 billion (see part (b) of the response to interrogatory 2-Staff-73). Subsequently, all programs were thoroughly reviewed, and various alternatives were evaluated, as documented in the individual investment plans in Schedule 2-5-7 - System Renewal Investments. Financial constraints, aligned with the chosen alternative, were then applied within Copperleaf PA.

f) Hydro Ottawa did not identify investments as "mandatory" during the Business Planning Process described in part (a), and therefore cannot provide a percentage of investments that were deemed mandatory. While Hydro Ottawa recognizes that investments related to maintaining a safe and reliable distribution system and mandatory service obligations within the Distribution System Code would be considered mandatory, it has not undertaken a specific exercise to classify investments in this manner.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-56

EVIDENCE REFERENCE:

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

Preamble:
Hydro Ottawa states that “system renewal investments prioritize replacing high-risk assets to mitigate immediate failures, they also require increased O&M spending on testing, inspection, and maintenance for remaining high-risks assets [...] System Service investments, which support grid expansion and the integration of new technologies, will inherently increase O&M costs due to the greater number of assets and specialized maintenance needs associated with advanced technologies”

QUESTION(S):

a) The premise of this claim appears to be contradictory: replacing more poor condition assets requires spending more on the remaining reduced set of poor condition assets. Please explain why "substantial system renewal investments", which presumably involves replacing a greater than historical volume of high-risk assets that would otherwise absorb a disproportionate level of annual maintenance spending compared with lower risk assets, "require increased O&M spending on testing, inspection and maintenance for remaining high-risks assets".

b) Historically, system service capital investments to modernize the grid have at least partly been justified by claims of the O&M cost savings expected to accrue to the investments, because, for example:

- The associated operating flexibility enables remote sectionalizing and switching, allowing a larger proportion of interrupted load to be restored prior to rolling a truck
- Improved fault sensing rapidly & accurately locates faults, enabling more efficient dispatch and restoration efforts

- installing modern condition monitoring sensors on high-value equipment such as transformers and breakers enables real-time warnings of emerging operational risks, permitting extended manual inspection cycles and helping the utility to focus its attention on problem assets.

Please discuss why the proposed tripling of historical levels of system service investment (which already exceeded OEB approved amounts) are now counter-intuitively expected to increase rather than reduce O&M costs.

RESPONSE(S):

a) Asset condition (represented by health index), is a key input into the Copperleaf Predictive Analytics (PA) model, which then forecasts asset degradation and calculates future asset risk levels. This allows Hydro Ottawa to make more informed, risk-based investment decisions for system renewal, as discussed in Section 4.4.1 Implementation of Predictive Analysis in Schedule 2-5-4 - Asset Management Process.

As outlined in Section 2.3.2 of Schedule 2-5-1 - Distribution System Plan Overview, the investment required to replace all assets that are projected to be in degraded condition by 2030 is estimated at $862M - this would effectively reduce the percentage of assets in degraded condition to 0% by 2030. Competing financial priorities, notably growth, electrification, grid modernization, and resilience, render this investment level impractical. Alternatively, Hydro Ottawa is proposing an investment of $261M over the 5-year period, which is projected to result in 8% of the overall assets being in degraded condition by 2030.

Consequently, not all high risk assets are slated to be replaced through the 2026-2030 period. Hydro Ottawa's risk-mitigation asset renewal strategy relies heavily upon condition information from maintenance inspections. Tackling the backlog of assets in a deteriorated condition but not replaced by 2030 (still posing a high risk to the system) necessitates adjustments to both the frequency and scope of the distribution and stations testing, inspection, and maintenance programs. To further improve upon the condition data accuracy, Hydro Ottawa will implement advanced inspection technologies enabling targeted maintenance and improved asset health

assessments. This helps refine future renewal plans, optimize replacement schedules, and inform the design of even more resilient new systems.

b) The proposed tripling of historical levels of system service investment is primarily driven by the Capacity Upgrade program and not necessarily the grid modernization initiatives outlined in the examples provided in the question. For more details please refer to the response to part (a) of interrogatory 2-Staff-108.

While modernizing the grid with technology such as remote sectionalizing, improved fault sensing, and condition monitoring is intended to reduce costs associated with truck rolls and reactive repairs, new smart devices introduce a new set of maintenance requirements. The expanded maintenance programs for this advanced equipment, along with the need for specialized training and technical support, will necessitate an increase in spending. As a result, the costs associated with maintaining new technologies are projected to offset and even surpass the savings from improved operational productivity, leading to a counter-intuitive increase in overall O&M costs.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-57

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 10 (pdf Exhibit 2 part 4, pp. 10)

QUESTION(S):

a) Hydro Ottawa states “These two programs [Distribution System Observability and Distribution System Resilience] underscore a dedication to leveraging real-time data for optimized grid management and fortifying infrastructure against increasing climate vulnerabilities.” Please explain the definition of "optimized grid management" as per Hydro Ottawa’s usage (economics, efficiency, reliability, etc.).

RESPONSE(S):

a) “Optimized grid management” for Hydro Ottawa refers to the strategic and continuous improvement of the electricity distribution grid’s performance, primarily by leveraging real-time data and advanced technologies. Hydro Ottawa’s approach to optimized grid management directly supports, and is a fundamental to enable the five Grid Modernization Objectives outlined within the Grid Modernization Strategy. Please refer to Attachment 2-Staff-57(A) - Hydro Ottawa Grid Modernization Strategy 2025.

These five Objectives are:

1) Enhanced Reliability
    - Predictive Maintenance: Utilizing predictive analytics and enhanced inspection programs to transition to condition-based maintenance, optimize investment decisions, and prolong asset lifespan, thereby reducing reactive expenditures.

- Rapid Outage Management: Achieving faster and more precise outage detection and restoration through advanced monitoring, proactive failure detection, automated power quality control, and automated system restoration.

2) Adaptive Grid Flexibility
   - Non-Wires Solutions (NWS): Employing NWS and demand-side management programs to defer costly traditional infrastructure upgrades and mitigate peak demand.
   - Energy Distribution Optimization: Enhancing energy distribution, managing peak demand, and reducing system losses through advanced control systems such as ADMS and DERMS.
3) Fortified Resilience & Robust Security
   - System Hardening: Leveraging asset data to implement proactive measures like strategic undergrounding of vulnerable lines and feeder reconfiguration to improve grid robustness.
   - Cybersecurity Strengthening: Safeguarding critical infrastructure and customer data from cyber threats to maintain operational integrity.
4) Strengthened Customer Engagement & Empowerment
   - Customer Empowerment: Enhancing customer engagement by providing real-time energy data (e.g., via AMI 2.0), efficient billing, and tools for energy management and demand response participation.
5) Sustainable Decarbonization & Renewable Integration
   - Renewable Energy Integration: Enabling widespread electrification, integrating diverse renewable energy sources (DERs), and supporting the transition to a decarbonized economy.
   - Grid Capacity Expansion: Strategically expanding grid capacity through new stations and targeted upgrades to accommodate community growth from decarbonization.

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Grid Modernization Strategy

Hydro Ottawa Limited

2025

Approval - Grid Modernization Steering Committee

Name & Title	Signature	Date
Co-Chairs		
Ronnie Potvin Manager, Grid Technology	DocuSigned by: Ronnie Potvin 30F5B40E59374F7...	2025-06-04
Andrew Fawcett Supervisor, Distribution System Integration	Signed by: Andrew Fawcett 285AABC801A240A...	2025-06-04
Sponsors		
Guillaume Paradis Chief Operating Officer, Distribution & Generation	DocuSigned by: Guillaume Paradis A8115E39C3334D4...	2025-06-16
Mark Fernandes Chief Information & Technology Officer	Signed by: Mark Fernandes 7A673DDD6F71474...	2025-06-13
Members		
Laurie Heuff Vice President, Distribution System Planning & Asset Management	DocuSigned by: Laurie Heuff 7E31070D87DA4FF...	2025-06-12
Alex Kemp Vice President, System Operations and Program Execution	Signed by: Alex Kemp 28BCB7F0D6B741F...	2025-06-12
Andrew Willlis Director, Enterprise Applications	Signed by: Andrew Willis EF78A24F054C411...	2025-06-11
Sarah Green Director, IT Planning, Programs & Grid Technology	Signed by: Sarah Green FAADFFA1AC9F40F...	2025-06-10
Kristopher Lelliott Acting Director, System Operations & Grid Automation	DocuSigned by: 20A134667D541C...	2025-06-10
Shawn Carr Director, Energy Transition Customer Strategy & Innovation	DocuSigned by: Shawn Carr D0C8A1B29EA94F5...	2025-06-10
Steve Hawthorne Director, Distribution Program Delivery	Steve Hawthorne 3FFDCAB677014DC...	2025-06-08
Jenna Gillis Director, Distribution Engineering and Asset Management	Signed by: Jenna Gillis B97D83B8EF0A48D...	2025-06-06
Jojo Maalouf Director, Cybersecurity & IT Infrastructure	DocuSigned by: Jojo Maalouf B33EFDE7585C4A0...	2025-06-06

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Revision Sheet

Revision	Description of Change	Date	Initial
0	Initial release of 2025 document	2025-06-03	AF

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Acronyms and Abbreviations

Table 0-1: Acronyms & Definitions

Acronym	Definition
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage System
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
FAN	Field Area Network
FLISR	Fault Location Isolation & Service Restoration
IT	Information Technology
KPI	Key Performance Indicators
OT	Operational Technology
OTN	Optical Transport Network

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1 Introduction

The utility industry is in the midst of a profound transformation. While the traditional focus on aging infrastructure and reliable service remains critical, utilities are now facing a convergence of disruptive forces. Decarbonization is driving the integration of renewable energy sources, while electrification, fueled by the adoption of electric vehicles and heating systems, is placing unprecedented demands on the grid.

At the same time, climate change is increasing the frequency and intensity of extreme weather events, threatening grid resilience. This changing landscape is further complicated by the rise of “prosumers” - customers who both consume and generate electricity - leading to a more decentralized energy system. To keep pace with changing customer needs the regulatory environment is evolving, adding another layer of complexity.

To thrive in this new era, grid modernization must enhance the reliability, efficiency, and resilience of the electricity distribution system. This involves implementing innovative technologies, upgrading equipment, integrating new energy sources, and improved grid monitoring and control. This document outlines the strategic actions Hydro Ottawa needs to take to successfully modernize its grid, address both current and future challenges, meet evolving customer expectations, and ensure a sustainable energy future. Hydro Ottawa’s Grid Modernization journey is guided by the Grid Modernization Steering Committee which is governed by the Grid Modernization Terms of Reference.

2 Grid Modernization Strategy

2.1 Corporate Strategic Alignment

Hydro Ottawa Holding Inc. has developed a comprehensive strategic direction for 2021-2025 to address the evolving challenges and opportunities facing the utility industry. This strategy, which highlights an emphasis on grid modernization for Hydro Ottawa, aims to guide the corporation towards its mission and vision (**Figure 2-1**):



Figure 2-1: Hydro Ottawa Holding Inc.'s Mission & Vision Statements

Hydro Ottawa Holding Inc.'s Eight-Point Strategic Plan (**Figure 2-2**) is informed by five key external trends - decarbonization, digitization, decentralization, diversification, and demographics - collectively referred to as the "5 Ds". These trends are driving significant changes in the energy landscape and shaping the future of the utility industry.



Figure 2-2: Hydro Ottawa Holding Inc.'s Eight-Point Strategic Plan

3 Grid Modernization Mission & Vision

Hydro Ottawa Limited has established a mission and vision for Grid Modernization (**Figure 2-3**), which is aligned with the broader mission and vision of Hydro Ottawa Holdings Inc.



Figure 2-3: Hydro Ottawa Limited Grid Modernization Mission & Vision

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4 Grid Modernization Objectives

Hydro Ottawa's Grid Modernization journey, derived from the Hydro Ottawa Holdings Inc. Eight-Point Strategy, is guided by five objectives, as mapped in **Table 4-1**.

1. **Enhanced Reliability**

   Improve grid reliability through advanced monitoring, proactive failure detection, fast fault detection, automated power control, automated system restoration, and reduced outage times.

2. **Adaptive Grid Flexibility**

   Enable the grid to adapt to the changing energy demand and incorporate diverse energy sources.

3. **Fortified Resilience & Robust Security**

   Improve the grid's ability to withstand disruptions caused by system faults or extreme weather and protect its assets from cyber threats.

4. **Strengthened Customer Engagement & Empowerment**

   Engage and empower customers by providing them with real-time data, efficient billing, and tools to manage their energy use.

5. **Sustainable Decarbonization & Renewable Integration**

   Reduce carbon emissions and promote sustainability by optimizing grid planning and operations to support the integration of renewable energy sources.

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Table 4-1: Mapping of Grid Modernization Objectives to the Eight-Point Strategy

		Eight Point Strategy							
		Achieve net-zero operations by 2030	Become the partner of first choice for signature green energy and carbon reduction projects in our community	Accelerate digital transformation to enable sustainable business practices	Leverage and promote distributed energy resources	Continue to grow and diversify our revenue sources	Grow our social license to operate	Ensure organizational capacity, culture, and leadership to deliver in a post-pandemic environment	Continue to provide best-in-class customer service
Grid Modernization Objectives	1. Enhance Reliability			✓	✓		✓	✓	✓
	2. Adaptive Grid Flexibility	✓	✓	✓	✓			✓	✓
	3. Fortified Resilience & Robust Security			✓	✓		✓	✓	✓
	4. Strengthened Customer Engagement & Empowerment		✓	✓	✓	✓	✓	✓	✓
	5. Sustainable Decarbonization & Renewable Integration	✓	✓	✓	✓	✓	✓	✓	✓

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7 Grid Modernization Roadmap

The Grid Modernization Strategy lays the foundation for a comprehensive Grid Modernization Roadmap. The Roadmap defines the specific initiatives required to achieve the strategic objectives over the next 5years. Its primary goal is to help Hydro Ottawa prioritize and implement these initiatives systematically and efficiently.

Each initiative's progress will depend on its contribution to the overall strategy and its relationship to other initiatives.

To secure funding, through the Ontario Energy Board's rate approval process, each initiative will require a business case and narrative, followed by a detailed project execution plan outlining resource requirements, and expected outcomes.

The initiatives within the Grid Modernization Roadmap are structured into five portfolios that encompass various technologies, operational processes, cybersecurity processes, and business processes designed to help Hydro Ottawa achieve the five grid modernization objectives while supporting the 8-Point Strategy.

7.1 Grid Modernization Portfolios & Workstreams

1. **Business and Strategy**
   Adopt a comprehensive internal approach for Grid Modernization to:

   - Address, inform and respond to market drivers;
   - Align with planning and regulatory processes;
   - Align with other internal strategies/programs to ensure stakeholder alignment;
   - Streamline operational structures and processes;
   - Monitor progress; and
   - Adjust and adapt.

2. **Data & Asset Management**
   Establish a comprehensive data management and analytics framework that:

   - Aligns with grid modernization objectives;
   - Integrates data from various IT and OT systems;
   - Promotes strong data governance; and
   - Leverages real-time data and advanced analytics to generate actionable insights for informed decision-making.

   This approach will enable Hydro Ottawa to:

- Address the challenges and opportunities presented by DERs, EVs; electrification of heating and other emerging factors impacting distribution assets.
- Leverage data-driven insights and innovative technologies; and
- Optimize system investments to effectively manage increased electrification demand.

3. **Sensing and Switching Infrastructure**
   Implement a comprehensive sensing and measurement strategy by integrating AMI 2.0, sensor technologies, and remotely operable switches with existing grid management systems to:

   - Optimize grid operations;
   - Provide valuable services and insights to customers; and
   - Improves overall cost-effectiveness of operations.

4. **Communication**
   Develop strategies for communication technology by prioritizing solutions that offer long-term benefits in interoperability, scalability, and support grid modernization initiatives.

5. **Control and Optimization**
   Adopt innovative control and optimization technologies, such as ADMS, DERMS and FLISR to enable Hydro Ottawa to:

   - Remain at the forefront of grid modernization,
   - Continuously monitor and assess emerging solutions
   - to proactively address future challenges and opportunities.

The Five Grid Modernization Portfolios are further divided into workstreams, as illustrated below in **Table 7-1**.

Table 7-1: Grid Modernization Portfolios and Workstreams

Portfolio	Workstream
1. Business & Strategy	1.1 Grid Modernization Strategy 1.2 Key Performance Indicators 1.3 Grid Modernization Governance Formation
2. Data & Asset Management	2.1 Distribution Asset Management 2.2 Hosting Capacity Development
3. Physical Infrastructure	3.1 Advanced Metering Infrastructure 3.2 Sensors 3.3 Switches 3.4 Battery Energy Storage Systems
4. Communication	4.1 Optical Transport Network 4.2 Field Area Network
5. Control & Optimization	5.1 Advanced Distribution Management System 5.2 Distributed Energy Resource Management System 5.3 Fault Location Isolation & Service Restoration

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7.2 Portfolio Workstreams

7.2.1 Business & Strategy

The Business & Strategy Portfolio is focused on guiding the progress of Grid Modernization of Hydro Ottawa Limited, details of the associated workstreams are presented in **Table 7-2.**

Table 7-2: Business & Strategy Workstreams Summary

Workstream	Work Summary
1.1 Grid Modernization Strategy	Continuous review and updates of the Grid Modernization Strategy to adapt to the evolving energy landscape and customer needs, thereby promoting efficient and effective project delivery.
1.2 Key Performance Indicators	Development and maintenance of Key Performance Indicators (KPI's) to monitor grid modernization progress such that strategic adjustments can be made based on quantitative metrics of performance.
1.3 Grid Modernization Governance Formation	Development of Grid Modernization Governance to ensure effective corporate organization, review and approval Grid Modernization related planning and work.

7.2.2 Data & Asset Management

The Data & Asset Management Portfolio is focused on developing effective tools and processes to better harness data to support decision making, details of the associated workstreams are presented in **Table 7-3.**

Table 7-3: Data & Asset Management Workstreams Summary

Workstream	Work Summary
2.1 Distribution Asset Management	Enhancement of distribution asset management, utilizing advanced technology to improve management of asset data and allow for integration with other systems to bolster available data for decision making.
2.2 Hosting Capacity Development	Develop efficient processes and tools for assessing load capacity within distribution system regions to evaluate the system's ability to accommodate new connection requests.

7.2.3 Physical Infrastructure

The Physical Infrastructure Portfolio is focused on the deployment of physical infrastructure required to facilitate other portfolios including increased grid observability, control, and dynamic capacity; details of the associated workstreams are presented in **Table 7-4.**

Table 7-4: Physical Infrastructure Workstreams Summary

Workstream	Work Summary
3.1 Advanced Metering Infrastructure (AMI)	Deployment of AMI 2.0 technology to address functional obsolescence with current metering infrastructure, simplify customer billing, provide more customer visibility, and provide near-real-time consumption data.
3.2 Sensors	Strategic deployment of sensors within the distribution network, identify unplanned outages faster, reducing outage times.
3.3 Switches	Strategic deployment of switches across the distribution network will improve grid control. This enhancement will enable remote switching capabilities, leading to quicker power restoration for customers experiencing unplanned outages.
3.4 Battery Energy Storage Systems (BESS)	Deployment of BESS's at key locations in the distribution network to provide on-demand capacity to mitigate temporary grid constraints and overloads.

7.2.4 Communication

The Communication Portfolio is focused on the deployment and expansion of communication networks to support field devices such as sensors, switches, and meters; details of the associated workstreams are presented in **Table 7-5.**

Table 7-5: Communication Workstreams Summary

Workstream	Work Summary
4.1 Optical Transport Network (OTN)	Expansion of Hydro Ottawa's optical transport network to provide reliable communication to field devices.
4.2 Field Area Network (FAN)	Deployment of a field area network to simplify communication with field sensors.

7.2.5 Control & Optimization

The Control & Optimization Portfolio is focused on enhancing Hydro Ottawa's ability to control and optimize the distribution network; details of the associated workstreams are presented in **Table 7-6.**

Table 7-6: Control & Optimization Workstreams Summary

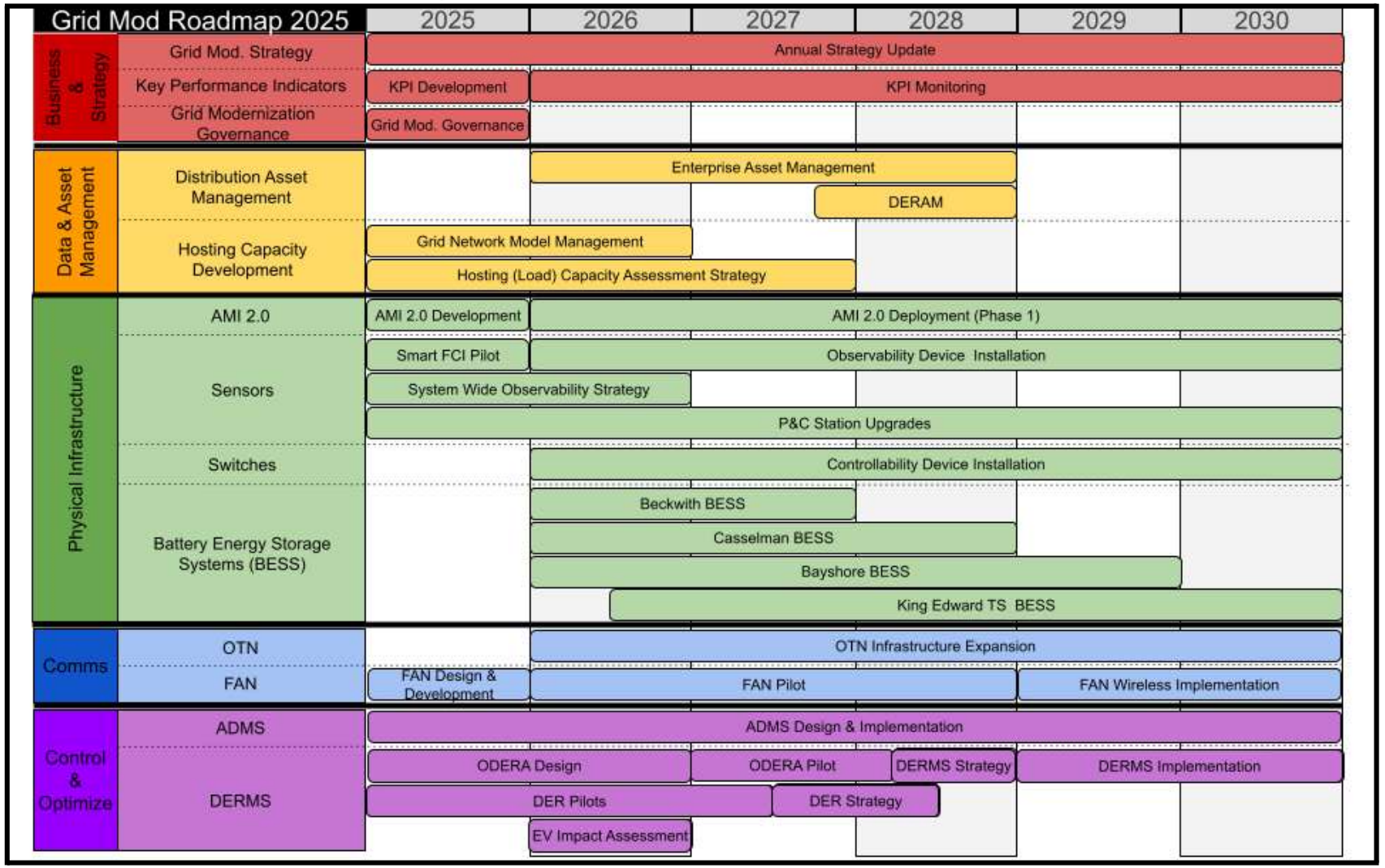
Workstream	Work Summary
5.1 Advanced Distribution Management System (ADMS)	Implementation of an advanced distribution management system is proposed to enhance grid control for system operators, optimize grid performance through data utilization, and introduce advanced planning tools and practices leveraging the data derived from the ADMS deployment.
5.2 Distributed Energy Resource Management System (DERMS)	Implement a comprehensive system for monitoring, controlling, and optimizing a diverse and growing portfolio of Distributed Energy Resources (DERs). This system will maximize DERs' potential to enhance local grid stability, optimize operational efficiencies, and facilitate the integration of more clean energy. It will also specifically enable DER pilot projects that will inform the broader DER strategy and the implementation of a DERMS. Beyond immediate DER management, this initiative will investigate advanced grid planning methodologies and explore the development of innovative local distribution market participation mechanisms.

7.2 Roadmap Timeline Chart

The Roadmap Timeline Chart will be maintained separately to reflect changes in timelines, drivers and dependencies. **Figure 7-1** is the current version of the roadmap at time of approval of this document. The roadmap gives a 5 year look ahead to 2030. Details of the project underneath each workstream can be found in each specific project's charter.

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Figure 7-1: Gird Modernization Roadmap 2025-2030



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2-Staff-58

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 26 (pdf Exhibit 2 part 4, p. 26)

QUESTION(S):

a) Hydro Ottawa stated that “An updated planning analysis demonstrated that 4kV to 13kV voltage conversion would better address immediate capacity needs while also effectively eliminating the original rebuild requirement arising from asset conditions.” Please explain if the voltage conversion eliminates the original asset condition driven rebuild of Dagmar station because the deteriorated assets will instead be removed from service, or for some other reason.

RESPONSE(S):

a) Yes, the voltage conversion eliminates the original asset condition driven rebuild because the deteriorated assets will instead be removed from service. More details on Hydro Ottawa’s voltage conversion strategy can be found in Section 9.1.4.6 of Schedule 2-5-4 - Asset Management Process.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-59

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 41, 73 (pdf Exhibit 2 part 4, pp. 41, 73)

Preamble:
Hydro Ottawa states, regarding Inflationary Pressures, that transformer costs have increased 124.0% since 2024 and 182.4% since 2020, and wood pole costs have increased 53.5% since 2024 and 120.2% since 2020. Hydro Ottawa also notes that its pole replacement program budget increased "by $17M and supports the replacement of 395 poles annually, which is in line with the proposed replacement rate of 400 poles in the historical period. $8M of the budget increase is associated with the increased cost per pole experienced in the historical period. The remaining $9M of the budget increase is attributed to incremental budget allocation to allow for resilience improvements to be incorporated into the renewed design. Productivity improvements have maintained cost efficiency, even with increased volume and inflation. Overhead transformer replacement costs are integrated within this program."

QUESTION(S):

a) Please provide documentation of any re-evaluation by Hydro Ottawa of the economic life of transformers and the value of life extension investments, considering that the significant increase in new transformer costs effectively increases the value to ratepayers of keeping existing transformers in service as long as possible.
    i) If no documentation is available, please discuss.
b) Given the significant recent increase in wood pole costs:
    i) Please provide documentation of any investigation done by Hydro Ottawa into alternative pole rehabilitation and strengthening techniques, such as stubbing and applying carbon fiber wraps. If no documentation is available, please discuss.

ii) Please provide documentation of any analysis done to re-evaluate the benefit/cost of wood pole replacement. If no documentation is available, please discuss.

c) If the benefits of wood pole replacement are attributable to anything other than the reduced probability of condition-based pole failure, please describe the other benefits and show how their value is calculated, with examples.

d) What percentage of Hydro Ottawa pole failures are caused by assessed pole condition? If the answer is different during Major Event Days and non-Major Event Days, please show both percentages.

RESPONSE(S):

Hydro Ottawa notes the preamble should state: Hydro Ottawa states, regarding inflationary Pressures, that transformer costs have increased between 124.0% to 182.4% in 2024 when compared to 2020, and wood poles have increased between 53.5% to 120.2% in 2024 when compared to 2020 (see Schedule 2-5-5 - Capital Expenditure Plan, Section 5.1.2, page 41, lines 20 and 22).

a)

i) Hydro Ottawa is not aware of any life-extension investments that can be made while the transformer remains installed, as removal (effectively, capital renewal) is required for refurbishment. Hydro Ottawa has an on-site transformer shop where transformers are typically evaluated in detail once removed from service. Comprehensive electrical testing and detailed visual inspections/checks of underlying sub-components are performed to assess the need for repairs and refurbishment. If deemed cost-effective, considering factors such as the remaining useful life and overall condition, transformers are then repaired in-house or sent to a third-party for refurbishment.

b)

i) Currently, there is no formal documentation of any investigation conducted by Hydro Ottawa into alternative pole rehabilitation and strengthening techniques. This investigation is ongoing and forms part of a wider continuous improvement initiative.

Hydro Ottawa is committed to proactively managing its aging overhead asset population. To this end, Hydro Ottawa is in the preliminary stages of reviewing and investigating various pole rehabilitation and strengthening techniques, including the use of carbon fibre wraps.

Any decision to implement pole rehabilitation, refurbishment, or strengthening must align with the asset management strategy and comply with all regulatory requirements, including O. Reg. 22/04.[1] This regulation ensures that all equipment, whether new or refurbished, meets safety and reliability criteria before being put into service.

ii) Hydro Ottawa assesses the "net value of intervention" for assets, including wood poles, by comparing various risk measures (reliability, safety, environmental, financial, and compliance) against the replacement cost. This calculation is detailed in Figure 11 of Schedule 2-5-4 - Asset Management Process. Copperleaf Asset's Predictive Analytics (PA) module determines the ideal replacement date for an asset by analyzing the aforementioned risk measures and specific replacement costs. This is achieved by balancing the maximization of value with the minimization of risk and cost. Figure 13 in Schedule 2-5-4 - Asset Management Process further illustrates the weighting factors that contribute to this overall value function. Hydro Ottawa evaluates all asset renewal projects (including pole renewal) to ensure there is a positive value to their replacement.

This systematic approach ensures that Hydro Ottawa's investment plans align with its strategic objectives, leading to higher-value decisions, enhanced business performance, and optimized resource allocation.

c) There are benefits other than reduced probability of condition-based failure that are considered for wood poles. The benefits differ, however, when considering wood poles as individual assets compared to their replacement as part of a project. For a single pole, the benefit (or value) is determined by weighing the reduction in risk against the cost of replacement. At the project

[1] Electrical Safety Authority, Distributor Bulletin, DB-05-14-v1, esasafe.com/utilities/bulletins

level, however, a broader range of benefits and risks are considered, as described in the sections below.

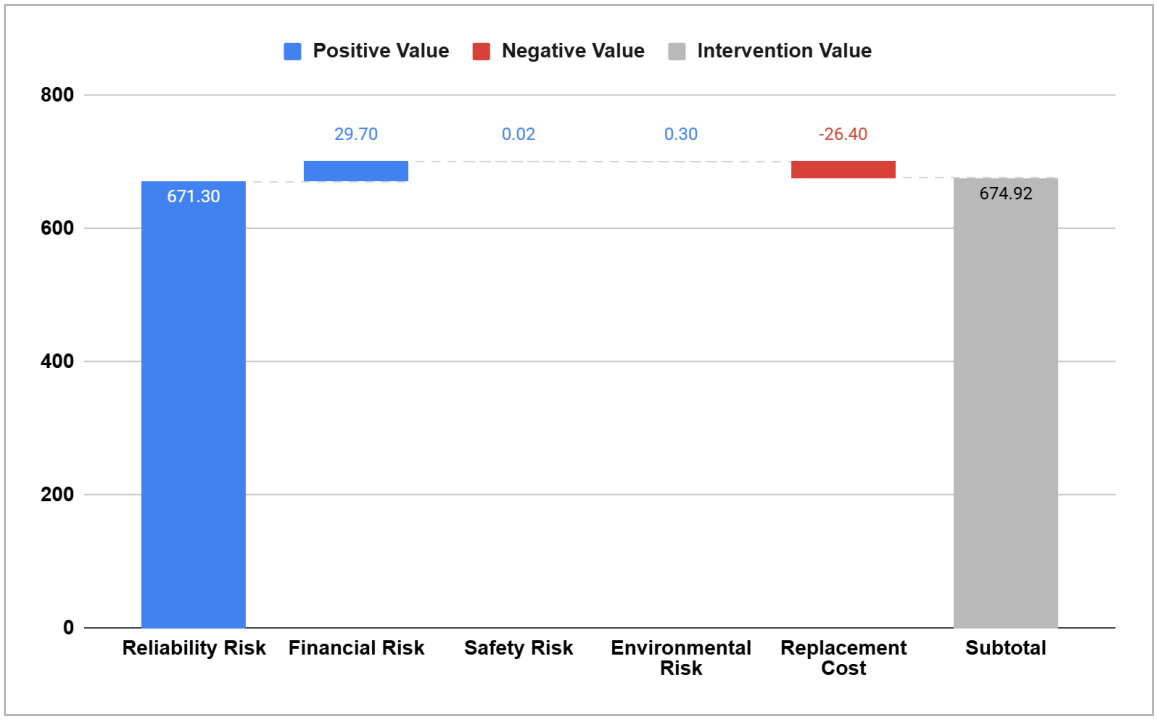
Individual Asset Value Calculation:

Beyond just reliability, the benefits of replacing an individual pole include reducing financial, safety, and environmental risks. The calculation of reliability risk considers the consequences and likelihood of a failure, such as outage duration, the number of affected customers, and the performance of the feeder. Financial risk accounts for the likelihood and consequence by considering the cost of both planned and unplanned replacements, as well as ongoing maintenance costs. To determine environmental risk, the potential consequences and likelihood of incidents like oil or SF_6 leaks are assessed. Safety risk is calculated by considering the potential consequences of a safety incident (e.g., lost-time accidents, injuries, or deaths to staff and the public) and the probability of it occurring. The overall intervention value (net benefit) is then calculated using this formula:

$$\textit{Intervention Value} = \textit{Reliability Risk} + \textit{Financial Risk} + \textit{Safety Risk} + \textit{Environmental Risk} - \textit{Replacement Cost}$$

Hydro Ottawa leverages Copperleaf Predictive Analytics (PA), to calculate the Intervention Value of individual assets based on the formula provided above. This process is used across all major asset types to inform asset renewal decisions. Further details on the methodology are outlined in Section 5.1.4.3 of Schedule 2-5-4 - Asset Management Process. An example output for a specific pole is illustrated in Figure A. In this example, the total intervention value was calculated at 674.92 value units. In this case, reliability and financial risks were the primary risk measures.

Figure A: Sample Pole Intervention Value



Project Value Calculation:

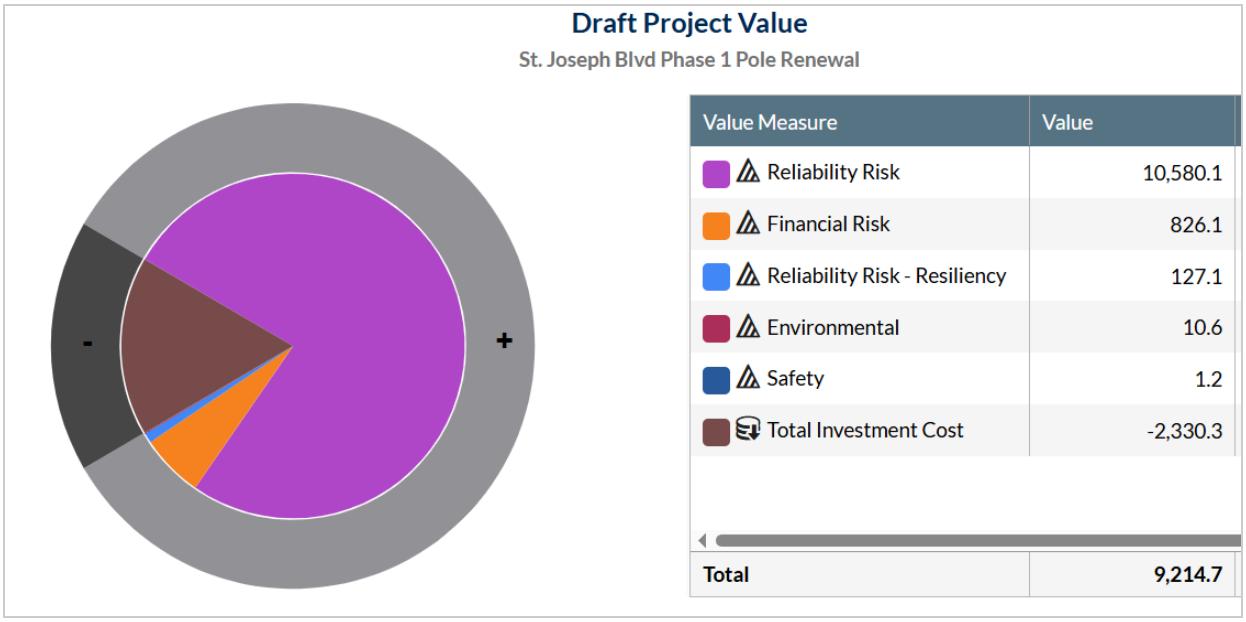
Because poles are replaced as part of larger projects, not individually, Hydro Ottawa also ensures that each project as a whole provides a positive net value. Using Copperleaf Portfolio, projects are scored based on a variety of benefits. While risk reduction is a major factor in pole renewal projects, other incremental benefits are also considered. The specific value measures used for scoring are detailed in the Asset Management Process (Section 5.3.2.2 of Schedule 2-5-4). A summary of the value measures considered is provided in Table A below for ease of reference.

Table A - Copperleaf Value Model

Asset Management Objective	Value Measure	Value Category
Resource Efficiency	Financial Benefits & Costs	Benefit Value Measures
Levels of Service	Program Effects	
Levels of Service	Distributed Generation	
Asset Value	Technological Innovation	
Levels of Service	Capacity Risk	Risk Value Measures
Compliance	Compliance Risk	
Health, Safety & Environment	Environmental Risk	
Resource Efficiency	Financial Risk	
Levels of Service	Reliability Risk	
Levels of Service	Resilience Risk	
Health, Safety & Environment	Safety Risk	
Resource Efficiency	Total Investment Cost	Cost Value Measure

Figure B below illustrates an example of a valuation for a pole renewal project that generated a net positive value of 9,214.7 units. In this specific example, financial, resiliency, environmental and safety risk reduction were also all factors contributing to the positive value of the project.

Figure B: Sample pole renewal project with value measures realized using Copperleaf Portfolio (project level)



d) Hydro Ottawa started tracking the age and health index at the time of asset failure from 2023. Since this exercise, Hydro Ottawa has observed two pole-related outages in 2023 and five in 2024 (excluding major event days). Out of the seven outages, three of them (43%) were caused by pole conditions. Apart from that, Hydro Ottawa has observed outage impacts primarily due to pole attachments, as shown in Schedule 2-5-3, Table 26 (page 56).

Hydro Ottawa doesn't regularly track the condition of poles impacted by Major Event Days, except for significant weather events such as the 2022 Derecho. A summary of the condition assessment based on poles impacted by the Derecho event is discussed in Hydro Ottawa's response to part (a) of interrogatory 2-Staff-29. From the 2022 Derecho event, 52% of the poles impacted by the Derecho event were in a Very Poor/Poor condition. A pole's ability to withstand extreme weather is not solely determined by its condition, but also by other critical elements, as detailed in CSA 22.3 No. 1: Overhead Systems. This topic is further elaborated in Hydro Ottawa's response to part (a)(iii) of interrogatory 2-Staff-36.

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2-Staff-60

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / pp. 127-128 (pdf Exhibit 2 part 3, pp. 127-128)

Preamble:
Hydro Ottawa states “From 1993 to 2023, Hydro Ottawa monitored the number of days when wind gusts exceeded 70 km/h, as illustrated in Figure 24.”

QUESTION(S):

a) Are the wind speed data sources consistent in all years of Figure 24? Please explain.
b) Please provide a revised version of Figure 24 that separately shows the Environment Canada data at the airport for each year.
c) Please provide documentation of any analysis or investigations conducted by Hydro Ottawa into the causes of the step change in number of days with winds above 70 km/h that occurred in 2011.
d) What are the average wind speeds for the years 1993 to 2023?

RESPONSE(S):

a) Yes, all wind speed data sources in Figure 24 were consistent. The data used was obtained from the weather stations Ottawa MacDonald-Cartier International Airport from 1993 to 2010 and Ottawa International Airport from 2011 to 2023, using historical data from the website Government of Canada/Environment and Natural Resources/Weather, Climate and Hazard/Past Weather and Climate at https://climate.weather.gc.ca/.

b) The weather data presented is obtained from Environment Canada. Please see the response to part (a).

c) No specific analysis or investigation was conducted by Hydro Ottawa into the causes of the step change in the number of days with winds above 70 km/h that occurred in 2011.

d) Hydro Ottawa does not track yearly wind speeds as wind is highly variable over a short time period and averaging over a year would smooth out high winds.

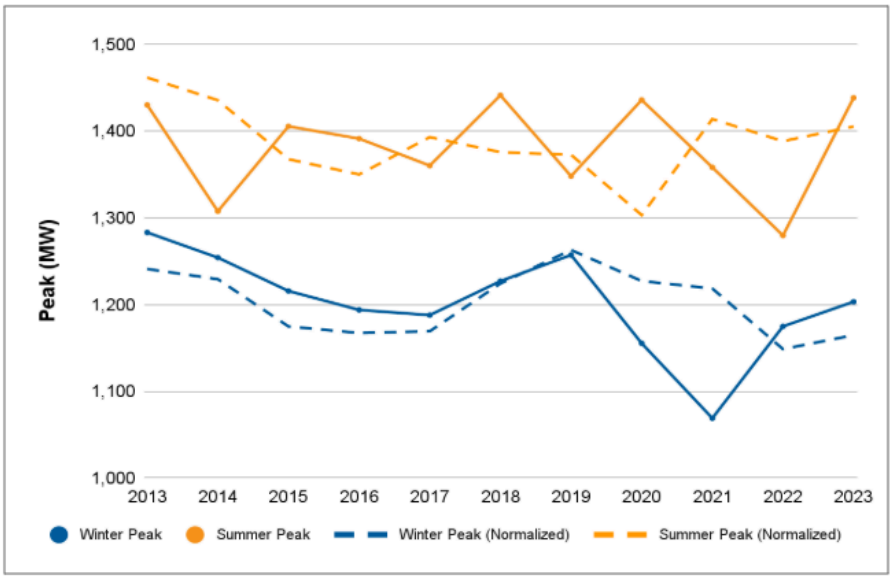
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2-Staff-61

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 135 (pdf Exhibit 2 part 3, p. 135)

Figure 25 - Net System Summer & Winter Peak (2013-2023)[11]



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

Preamble:

Figure 25 illustrates “both the summer and winter peak demands from 2013 to 2023.” Hydro Ottawa states “To ensure continued delivery of reliable and resilient electricity services to its expanding customer base, Hydro Ottawa must strategically expand its grid capacity to accommodate unprecedented demand growth.”

QUESTION(S):

a) Please explain the inter-annual variability in the normalized summer and winter peak values shown in Figure 25.
b) Does the inter-annual variability indicate that Hydro Ottawa's normalization calculations should be revised? Please discuss.
c) Figure 25 appears to indicate flat or decreasing trends in both actual and normalized winter and summer peaks. Please explain when the "unprecedented demand growth" is expected to occur.
d) Please reconcile the claim that there is a growing demand for electricity due to a "combination of residential intensifications" described in reference 2, with the apparent flat or decreasing peak demand trends shown in Figure 25.

RESPONSE(S):

a) The inter-annual variability in the normalized summer and winter peak values shown in Figure 25 is primarily due to real-life socio-economic events and weather-related variabilities. Specifically, the impact of COVID-19 from 2020 dampened predictable load growth as many loads went offline during lockdowns, and there was a subsequent impact of the post-COVID recession on development and business.

b) Hydro Ottawa does not believe its normalization calculations should be revised because the inter-annual variability is mainly attributed to factors other than weather as explained in the response to (a) above.

c) Figure 25 plots real, historical data and as such is affected by real-life socio-economic events. Additionally, demand growth is a regional phenomenon. System coincident peaks may not always capture the significant growth in certain areas that are responsible for regional capacity constraints. It is also important to note that although system coincident peak is a universally used measure to gauge the capacity of the overall system, there are some load requirements that do not contribute to the system coincident peak but still need to be made available.

The "unprecedented demand growth" is expected to occur in the 2026-2030 period. This is when most large load requests, currently in project planning or construction stages, are anticipated to be energized. More details on large load requests can be found in Section 2.3.1 of Schedule 2-5-1 - Distribution System Plan Overview. For more insight into regional capacity concerns as a consequence of regional demand growth please refer to section 9 of Schedule 2-5-4 - Asset Management Process.

d) The apparent flat or decreasing peak demand trends shown in Figure 25 can be reconciled with the claim of growing electricity demand due to residential intensifications by considering factors detailed below:

i) Impact of Socio-Economic events: Figure 25 plots real, historical data affected by real-life socio-economic events and not directly impacted by residential intensifications. These external factors can mask underlying growth trends.

ii) Regional vs. System-Wide Coincident Peaks: Demand growth is often a regional phenomenon. While there might be significant growth in specific areas due to residential intensification, this growth may not always contribute proportionally to or be fully captured by the system-wide coincident peak. Localized capacity constraints can still emerge even if the overall system peak appears flat or decreasing.

iii) Non-Coincident Load Requirements: Not all load requirements contribute to the system coincident peak, but they still necessitate available capacity. This means that even if the peak doesn't rise, the overall demand for electricity can still be increasing due to these non-coincident loads.

iv) Future Growth Projections: Please refer to the response to interrogatory 2-Staff-42 on the methodology used by Hydro Ottawa to forecast residential growth in the 2026 - 2030 period. Figure 25, being historical, does not reflect this projected future growth.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-62

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 185 (pdf Exhibit 2 part 3, p. 185)

Preamble:
Figure 66 highlights a significant reliability risk value for poles.

QUESTION(S):

a) For Toronto Hydro, the annual probability of failure for “Wood Poles” that are assessed to be in the worst health index condition (HI5) is 0.18% to 0.33%. What is the estimated annual probability of failure for poor condition wood poles in Hydro Ottawa’s system? Please explain how that probability was determined? [1]

b) How does Hydro Ottawa determine when a wood pole should be replaced? Please describe whether this is based on age, condition, or other factors.
   i) What distribution wood pole TUL changes have resulted from recent data collection efforts and inspection results?
   ii) Please explain if these TUL changes have resulted in changes in distribution wood pole replacement practices or pacing.

c) Please explain how Hydro Ottawa calculates the probability of failure for wooden poles, including whether this is based on empirical data (e.g., historical failure rates by condition, age, or type).
   i) If failure rates are not empirically derived, please explain the basis for any assumed failure probabilities used in asset management decision-making.

[1] EB-2023-0195, THESL_IRR Exhibit 2B_Part1of3_20240311, 2B-Staff-134, Table 1, p. 3 of 4

ii) If no such estimate is available, please explain why this information is not available and indicate what plans Hydro Ottawa has to develop such failure modeling in the future.

RESPONSE(S):

a) Hydro Ottawa can not refer to or comment on Toronto Hydro's specific probability of failure (PoF) calculation methodology without a comprehensive understanding of their asset management framework, which includes their condition dataset, failure information, asset database, and replacement strategies.

In 2024, Hydro Ottawa collaborated with Hatch to improve its understanding of asset failure curves. The goal was to enhance the utility's risk-based and value-based asset management framework. Hatch utilized statistical methods to analyze Hydro Ottawa's data, creating a simulated asset population that accurately mirrored Hydro Ottawa's actual asset registry. This analysis primarily focused on determining the most suitable Weibull curve parameters (a combination of shape and scale values), which is a standard industry approach for developing failure curves. As a part of the failure curve development process, the Cumulative Distribution Function (CDF) was developed by Hatch, which represents the probability that an asset will fail by or at a specific time, effectively showing the cumulative probability of failure over time. More information regarding the failure curves initiative is shown in Section 4.4.4 Failure Curves and Typical Useful Life Update of Schedule 2-5-4 - Asset Management Process.

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

The formula used is:

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

As per Hydro Ottawa's current wood pole condition failure probability curve, the overall probability of failure for poles in a Very Poor condition is 0.0772 (λ). For the annual PoF, the time variable (t) is set to 1 year. Applying this to the annual PoF formula, the annual probability of failure can be obtained as shown below:

$$\text{Annual PoF} = 1 - e^{-0.0772} \approx 0.07424$$

With 1,331 poles currently in the Very Poor condition category (in 2024), as shown in Figure 28 of Schedule 2-5-7 - System Renewal Investments (page 56), the expected number of annual failures is approximately 99 poles (1,331×0.07424 = 98.77). Therefore, Hydro Ottawa has budgeted the corrective renewal program (unplanned replacement) for poles accordingly, to intervene on 100 poles each year as outlined on page 163, Section 6.6.1 Alternatives Considered of Schedule 2-5-7 - System Renewal Investments.

b) Hydro Ottawa determines when a wood pole should be prioritized for planned replacement based on a combination of age, condition and the overall risk, as determined through Copperleaf Predictive Analytics (PA). The enhanced view of asset failure risk mitigation through Copperleaf PA has allowed Hydro Ottawa to plan its wood pole interventions accordingly, based on understanding the optimal intervention time for a given wood pole in the service territory. More information on this asset risk assessment process based on Copperleaf PA is highlighted in Section 5.1.4 Asset Risk Assessment of Schedule 2-5-4 - Asset Management Process. The criteria used to assess the requirement for pole replacement under emergency renewal and critical renewal can be found in Table 25 and Table 6, respectively of Schedule 2-5-7 - System Renewal Investments.

i) There has been no change to the TUL consideration for wood poles, as highlighted in Table 25 of Schedule 2-5-4 - Asset Management Process and the value remains at 53 years.

ii) Not Applicable.

c) In 2024, Hydro Ottawa engaged Hatch to enhance asset failure curve knowledge and insights, aiming to refine the utility's risk-based and value-based asset management framework. More information regarding the failure curves initiative is shown in Section 4.4.4 Failure Curves and Typical Useful Life Update of Schedule 2-5-4 - Asset Management Process.This initiative involved:

- A thorough review of existing failure curves.
- The development of new, data-driven failure curves.
- Augmentation of existing age-condition curves using asset registry data to improve accuracy.
- Establishing the typical useful life (TUL) values of the various asset types.

As a part of the data-driven failure curve development process, Hydro Ottawa provided Hatch with the asset registry information for all major asset classes, including:

- All asset-related information such as the voltage class, current rating, insulation type, installation date, health index, etc.
- Existing asset failure curves and TUL information
- Number of assets replaced each year (since 2016) within each asset class under the different OEB investment programs (System Renewal - Planned and Corrective, System Service, and System Access)
- Existing asset survival and failure records

Hatch employed statistical techniques to analyze and interpret the data provided by Hydro Ottawa to create a simulated asset population to align with Hydro Ottawa's actual asset registry. This analysis focused on deriving the best representative Weibull curve parameters (a matrix of shape and scale values), a common industry practice for failure curve development. This was the process for failure curve/probability of failure development for all asset types, inclusive of wood poles. More details regarding the failure curve and typical useful life update initiative can be found in Section 4.4.4 Failure Curves and Typical Useful Life Update of Schedule 2-5-4 - Asset Management Process.

i) The failure rates are empirically derived and based on Hydro Ottawa data, as discussed in part (c) above.

ii) Not Applicable.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-63

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 186 (pdf Exhibit 2 part 3, p. 186)

Preamble:
Hydro Ottawa states that “eight stations [are] already operating beyond planned capacity limits”.

QUESTION(S):

a) Please explain how Hydro Ottawa defines 100% station capacity. What are the contingency assumptions (i.e., N-0 or N-1,), and what are the station loading assumptions (i.e., coincident/non-coincident, summer peak/winter peak, etc.).
b) Does Hydro Ottawa utilize transformer nameplate ratings when determining station capacity or does Hydro Ottawa allow for short term thermal overload (within industry standard allowances) for short term peak loads?
c) Please provide a list of any stations for which capacity is limited by equipment other than power transformers, indicating for each such station the limiting equipment and the reason for the limitation.

RESPONSE(S):

a) For planning purposes, Hydro Ottawa defines 100% station capacity (also referred to as station planning capacity) as the sum of all the station's power transformers' Limited Time Ratings (LTRs), minus the LTR of the single largest transformer. This methodology incorporates an N-1 contingency assumption, meaning the system can continue to operate even if the largest transformer is out of service.

Regarding station loading assumptions, Hydro Ottawa's planning is based on the system coincident peak load for the year and the station loading that contributes to this coincident peak. This historically has been a summer peak; however, Hydro Ottawa anticipates a potential shift to a winter peak in the coming years and will adjust its planning accordingly if this occurs. Further details on this methodology are available in Sections 5.2.2.2 and 8.4.1 of Schedule 2-5-4 - Asset Management Process.

b) Yes, Hydro Ottawa allows for a short thermal overload of its transformers for short term peak loads. This is explained as the LTR or Limited Time Rating. This rating is in excess of the "ONAF2" rating, which is the maximum continuous manufacturer rating of the transformer with the fans set on the maximum airflow setting. The LTR is the absolute ceiling of safe operation, for which a minor amount of degradation may occur, but exceeding ONAF2 is exceptionally rare and so the cumulative degradation is not expected to significantly shorten the transformer's useful lifespan. More details on this methodology can be found in Section 5.2.2.2 and Section 8.4.1 of Schedule 2-5-4 - Asset Management Process.

c) Table A lists the stations where capacity is limited by equipment other than power transformers. All limiting equipment mentioned in Table A is owned by Hydro One.

Table A – Stations with Non-Transformer Capacity Limitations

Station	Limiting Equipment	Limiting Reason
Limebank MTS	Transmission Lines	Hydro One imposed megawattage limitation due to transmission line capacity constraints
Carling TS	Station Equipment	Transformer breakers and cables are limiting station capacity.
Lisgar TS	Station Equipment	Transformer breakers and cables are limiting station capacity.
King Edwards TS	Station Equipment	Transformer breakers and cables are limiting station capacity.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-64

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 187 (pdf Exhibit 2 part 3, p. 187)

Preamble:
Hydro Ottawa states the operating stations above their planning rating capacity "significantly reduces the system's flexibility to effectively manage both planned maintenance and operational activities, as well as respond to unforeseen disruptions or abnormal system states, such as equipment failures, power surges, or extreme weather events. This lack of flexibility can lead to cascading failures, [… which] can result in widespread power outages, service disruptions, and potential damage to equipment."

QUESTION(S):

a) Please provide any analysis carried out by Hydro Ottawa to determine the probability of station equipment failures occurring during station peak non-coincident load periods and provide examples of when this has occurred in the past.
b) Does Hydro Ottawa plan maintenance outages during peak loading periods? If yes, please explain and provide examples of when and why this would occur.
c) Please explain how operating below 100% capacity enables Hydro Ottawa to better respond to power surges and provide examples of when this flexibility has been used in the past.
d) Please provide examples of when cascading failures have been triggered as a result of stations exceeding their planning limits. When citing examples, please differentiate between cascading outages that occurred during extreme weather events such as tornadoes, derechos or ice storms, those that occurred during winter or summer peak conditions, and those that occurred during calm weather conditions.

RESPONSE(S):

Hydro Ottawa acknowledges the correction to the following Schedule 2-5-4 - Asset Management Process, page 187, line 4-6: *"Primarily, it significantly reduces the system's flexibility to effectively manage both planned maintenance and operational activities, as well as respond to unforeseen disruptions or abnormal system states, such as equipment failures or extreme weather events".* The submitted evidence introduced the term "power surge" which does not by itself introduce unforeseen disruptions or abnormal system states.

a) Hydro Ottawa has not carried out any analysis to determine the probability of station equipment failures occurring during station peak non-coincident load periods.

b) Hydro Ottawa assesses planned maintenance during peak load periods, particularly in capacity-constrained regions, to determine the nature and urgency of the work. Depending on the type of maintenance and its location, Hydro Ottawa either implements appropriate contingency/switching plans to prevent customer interruptions or schedules the work for periods outside of peak loading.

c) Hydro Ottawa acknowledges the question, which was based on Ref 1. from Schedule 2-5-4 - Asset Management Process, page 187, line 4-6. With the correction as outlined above and the removal of the term "power surge", the premise underlying the question no longer applies.

d) Hydro Ottawa has no record of cascading failures directly caused by station overloading. Hydro Ottawa proactively plans to ensure minimal stations exceed planning limits and has contingency plans for stations at or above these limits. This allows nearby stations to pick up the load if a problem requires de-energization. However, there have been occurrences of stranded customers in contingency plans due to a single asset failure or the need to remove multiple assets for maintenance. Furthermore, overloaded stations have led to additional customer impacts during outages and extended restoration times, as customers must be restored without exceeding thermal limits. For instance, before Cambrian MTS was energized, Fallowfield MTS

exceeded its planning capacity. This necessitated a contingency plan, involving the costly temporary relocation of a transformer, to address potential transformer failure during peak loading. While this solution would have ensured customer supply and prevented stranded load, it introduced additional risk at the source station. Similarly, Kanata North MTS is currently operating above its planning capacity. Should a transformer fail during peak loading, Hydro Ottawa would be unable to supply all the load from an alternate transformer. This would result in longer customer outages as distribution restoration methods are implemented, thereby increasing system risk and negatively impacting SAIDI.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-65

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 192 (pdf Exhibit 2 part 4, p. 192)

QUESTION(S):

a) Table 25 provides a summary of TUL values for various asset types. For poles towers and fixtures the TUL is 53 years. Are these Typical Useful Life values based solely on condition-related failures, or do they incorporate all-cause failures, such as third party (i.e., vehicle or equipment) contacts, failures caused by trees or branches falling on lines or against structures, or above design structure loads caused by ice build-up or extreme wind events such as tornadoes or derechos? Please discuss.

RESPONSE(S):

a) The TUL established for poles, towers and fixtures is solely based on condition-related failures. In 2024, Hydro Ottawa engaged Hatch to enhance asset failure curve knowledge and insights, aiming to refine the utility's risk-based and value-based asset management framework. Additional information regarding the failure curves and TUL update exercise with Hatch is outlined in Section 4.4.4 Failure Curves and Typical Useful Life Update of Schedule 2-5-4: Asset Management Process.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-66

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 210 (pdf Exhibit 2 part 3, p. 210)

Preamble:
Hydro Ottawa states it “monitors the percentage of feeders with a load index of 4 and 5 to plan for feeder capacity upgrades and reliability improvement investments. In 2023, 12 Hydro Ottawa feeders had a FLI of 4 and 19 feeders at a FLI of 5, as shown in Figure 70. Feeders must be maintained within the planning capacity to allow for efficient load transfer during N-1 contingency situations while respecting equipment ratings.”

QUESTION(S):

a) What is the typical duration of the peak loading levels used to calculate the feeder load indices? Please express in hours and as a percentage of total annual hours.
b) Using the annual load duration curve for Hydro Ottawa's system, for how many hours each year and for what percentage of the total hours in each year could the load on the average feeder be expected to exceed 90% of its non-coincident peak value for that year.
c) What percentage of Hydro Ottawa contingencies occur when feeder loading is above 90% of non-coincident annual peak?

RESPONSE(S):

Hydro Ottawa notes that the preamble should state: in 2023, 12 Hydro Ottawa feeders had a FLI of 4 and 20 feeders at a FLI of 5, as shown in Figure 70 of Schedule 2-5-4 - Asset Management Process.

a) Hydro Ottawa's current feeder loading evaluation and calculation of FLI does not account for peak duration. Current feeder capacity planning is based on loading at the time of system coincident peak, a traditional methodology with known limitations. To address this, Hydro Ottawa is in the process of evaluating new planning tools that will support the consideration of peak duration at both the feeder and station level.

The current feeder loading evaluation is conducted through the following process:

- System Co-Incident Peak Identification: Hydro Ottawa analyzes system loading data for every hour of the year to pinpoint the single hour when the total system load reaches its highest point. This is the system-wide coincident peak hour.
- Feeder Load at Coincident Peak: Once the system's peak hour is identified, Hydro Ottawa then determines the load on each individual feeder in that exact hour.
    - It's important to note that this feeder load does not necessarily represent the individual peak load for that particular feeder. A feeder's own highest load might occur at a different time due to the unique consumption patterns of its connected customers.
    - However, the feeder's load at the system-wide coincident peak hour is critical because it quantifies that feeder's contribution to the system's overall highest demand.
- Capacity Planning and Indices: This coincident peak load value for each feeder is then used to determine feeder load indices and guide capacity planning.

Due to this methodology, Hydro Ottawa is unable to provide feeder peak load hours as a percentage of total annual hours, as the focus is on a single, system-wide peak hour.

b) The methodology used by Hydro Ottawa to determine feeder capacity is explained in the response to part (a) above which does not employ information on hourly feeder loading and hence the information requested cannot be provided.

c) Hydro Ottawa does not monitor percentage of contingencies that occur when feeder loading is above 90% of non-coincident annual peaks. This is because Hydro Ottawa uses coincident peaks for feeder assessments as detailed in the response to (a) above.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-67

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / pp. 280-283 (pdf Exhibit 2 Part 3, pp. 280-283)
Ref. 2: Exhibit 1 / Tab 3 / Schedule 1 / p. 31 (pdf Exhibit 1 Part 2, p. 245)
Ref. 3: Exhibit 2 / Tab 5 / Schedule 8 / p. 49 (Table 2) (pdf Exhibit 2 Part 4, p. 413)

Preamble:
Hydro Ottawa notes that the initial portfolio of the Non-Wires Customer Solutions Program (NWCSP) consists of 4 individual programs that are under evaluation:

1. Save on Energy Retrofit Adder Program
2. Residential Demand Response (DR)
3. Commercial Demand Response
4. Solar PV and Energy Storage Program

In total, Hydro Ottawa expects the NWCSP to provide an additional 20-30 MW of capacity to address existing capacity constraints from large load requests and to provide immediate risk mitigation in the Kanata North (West 28 kV North), Core 13kV, and West 13kV regions. Hydro Ottawa anticipates costs of $2M per year for a total of $10M from 2026-2030 for the NWCSP.

Hydro Ottawa also notes it is exploring collaborative opportunities with the IESO where there is overlap between local distribution system and bulk system benefits and building upon province-wide incentive offers available through IESO's eDSM framework. Hydro Ottawa also mentions that IESO's Local Achievable Potential Study (L-APS) in Q2 2025 will be used to validate the programs.

QUESTION(S):

a) Please clarify the following related to each of the 4 individual programs:

i) The specific system need being addressed by each program.
ii) The specific region(s) where each program will be offered.
iii) The anticipated cost (in total and annually from 2026-2030) and the type of cost (capital expenditure or OM&A) for each program. See Table 1 below for guidance.
iv) The major activities and their associated timelines for each program.

b) Please provide the following details for each of the 4 individual programs and their corresponding traditional infrastructure solution. Please see Table 2 below, specifying the following for each individual program:
i) Quantitative and qualitative benefits (including avoided/deferred costs).
ii) Quantitative and qualitative costs.
iii) Any calculations Hydro Ottawa has completed to evaluate the cost-effectiveness of each of the 4 individual programs over traditional wire solutions, if any.

c) Please clarify the following related to the 4 individual programs:
i) Which of the 4 programs is Hydro Ottawa investigating for possible IESO collaborative funding?
ii) Does the $2M/year funding request exclude potential IESO funding for each of the 4 programs?
iii) How much IESO funding does Hydro Ottawa expect to receive from IESO for each program outside of the $2M/year?
iv) If IESO funding cannot be obtained, does Hydro Ottawa plan on modifying the program design and scope of any of the 4 individual programs? If so, how will each program change?

d) Please clarify whether and how the L-APS results might affect program design or spending for each of the 4 individual programs.

Table 1: Breakdown of Costs (NWCSP)

NWS Program	Cost Category	Cost ($)					
		2026	2027	2028	2029	2030	Total

Save on Energy Retrofit Adder	Capital						
	OM&A						
Residential DR	Capital						
	OM&A						
Commercial DR	Capital						
	OM&A						
Solar PV and Energy Storage	Capital						
	OM&A						
Total Capital							
Total OM&A							
Total Annual Spend							

1

2 Table 2: Benefits and Costs of NWCSP

Category	Save on Energy Retrofit Adder	Residential DR	Commercial DR	Solar PV and Energy Storage
Benefits				
A. Quantitative ($)				
A. Explanation				
B. Qualitative				
B. Explanation				

Costs				
C. Quantitative ($)				
C. Explanation				
D. Qualitative				
D. Explanation				

RESPONSE(S):

a) Hydro Ottawa has identified six individual programs slated for deployment as part of its Non-Wires Customer Solutions Program (NWCSP) portfolio. Following additional analysis, it became clear that the Solar PV and Energy Storage Program concept described in Section 9.2.2.1 of Schedule 2-5-4 - Asset Management Process should be further divided into 3 individual programs, separating offers for residential customers and commercial customers. This configuration aligns with Save on Energy programming announced as part of the eDSM framework. Thus, the list of programs expected to be deployed within the NWCSP is now as follows:

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

In addition, for further context contributing to the selection of the programming (priority, criteria considered), refer to response (b) within interrogatory 2-Staff-55.

i) The specific system needs being addressed by the NWCSP is capacity constraints, as assessed through Hydro Ottawa's NWS assessment criteria detailed in Section 9.2.1 of Schedule 2-5-4 - Asset Management Process. Based on this criteria it was determined that NWCSP can support Hydro Ottawa's West 28 kV (North) region and Core & West 13kV regions. For additional details about the system needs for these two regions refer to Sections 9.1.4.2.5 (West 28kV (North)) and 9.1.4.5 (13kV System) of Schedule 2-5-4 - Asset Management Process.

Hydro Ottawa will deliver the individual programs listed in answer (a) above simultaneously, operating them as a portfolio - each targeting different customers, resources or technologies - in order to address system needs in targeted areas, with the initial priority area for deployment the West 28kV (North) planning region. Hydro Ottawa is submitting a Benefit-Cost Analysis Summary Report as Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report for the initial deployment area. Section 3 of the report describes the system needs in the initial deployment area.

Additional details about the needs within the West 28 kV (North) region and Core & West 13kV regions can be found within Section 2.3.2.1 (New Kanata North MTS and Bronson DS Upgrade) and Section 2.3.2.3 (West 28kV (North) and Core 13kV and West 13kV system) of Schedule 2-5-8 - System Service Investments.

ii) While the NWCSP's initial deployment will prioritize the West 28kV (North) planning region (encompassing Kanata and Marchwood stations), the program will also be deployed across a broader area of Kanata to accelerate capacity acquisition and broaden customer accessibility. This broader deployment will include Bridlewood and Terry Fox stations - which are directly interconnected with Kanata and Marchwood, thereby providing global benefits in increasing flexibility in the system - meaning customers supplied by these stations will also be eligible to participate. This expanded reach aims to minimize customer confusion and more quickly meet system needs as described in Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report. This broader deployment area is shown in Figure A.

Given the results of the NWS Pre-Assessment for capacity needs in the Core 13kV and West 13kV, Hydro Ottawa also expects to deploy the NWCSP portfolio to target a subset of 13kV stations in subsequent phases, assuming the areas demonstrate a positive NPV when employing the BCA framework. A map of the Core 13 kV and West 13kV region is provided in Figure B.

Figure A - NWCSP Initial Deployment Region - Kanata

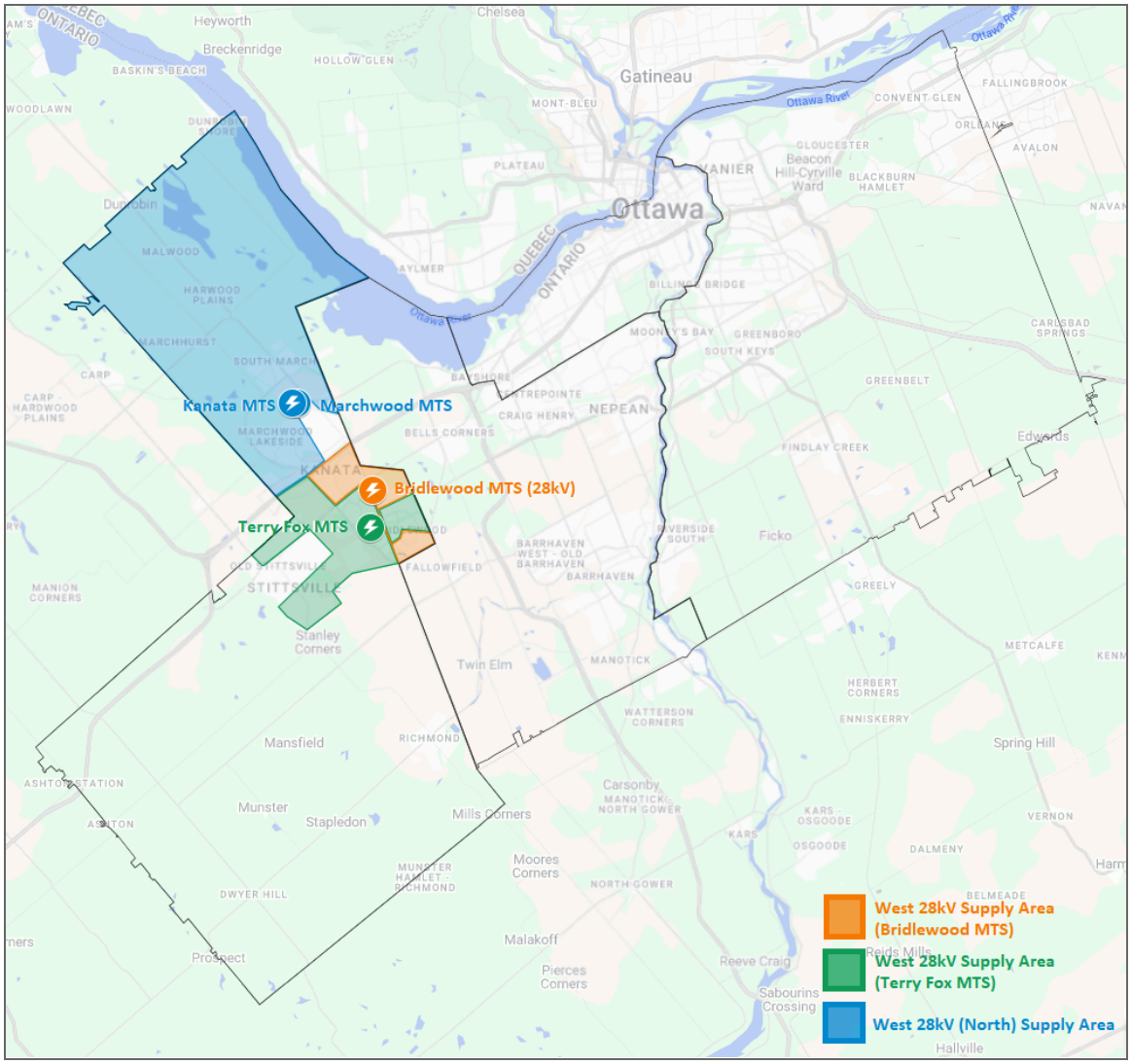
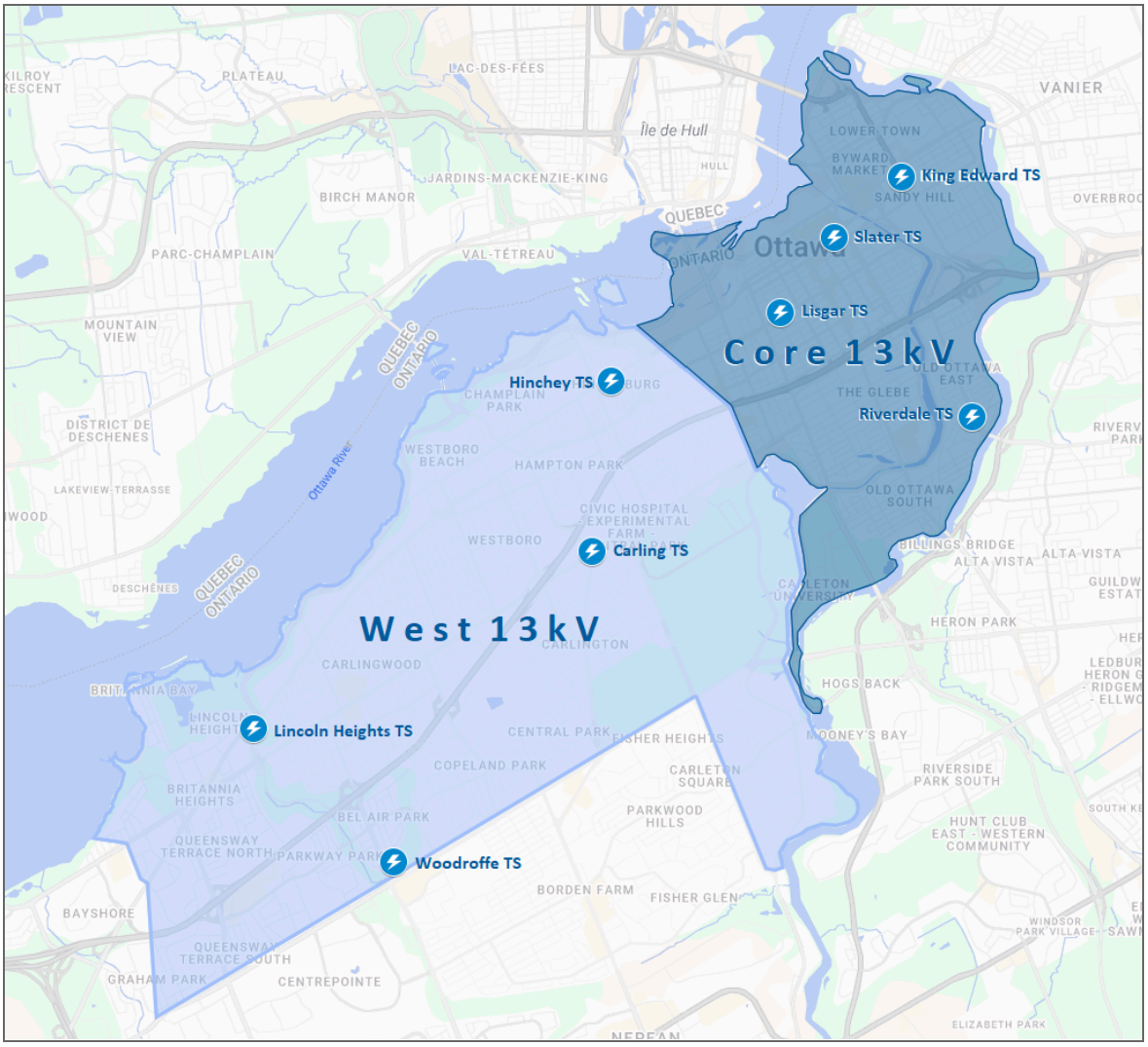


Figure B - 13kV Supply Region



iii) For a summary of all estimated costs associated with the NWCSP, refer to Table 6 within Section 4.4 of Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report.

iv) The major activities and timelines associated with each program are summarized in Table A.

Table A - Breakdown of NWCSP Major Activities

Program	Major Activities				
	2026	2027	2028	2029	2030
Commercial Retrofit Incentive Adder Program	• Program design and launch • Marketing, business development, customer support and enrollment begins	• Ongoing: ○ marketing ○ business development ○ customer support and enrollment	• Ongoing: ○ marketing ○ business development ○ customer support and enrollment	• Ongoing, if necessary: ○ marketing ○ business development ○ customer support	• Ongoing, if necessary ○ Marketing ○ business development ○ customer support
Residential Demand Response Program	• Program design and launch • Mass marketing • Customer enrollment • Local dispatch begins	• Ongoing: ○ mass marketing ○ customer enrollment ○ local dispatch	• Ongoing: ○ mass marketing ○ customer enrollment ○ local dispatch	• Ongoing, if necessary: ○ mass marketing ○ customer enrollment ○ local dispatch	• Ongoing, if necessary ○ mass marketing ○ customer enrollment ○ local dispatch
Commercial Demand Response (HVAC) Program	• Program design and launch ○ Business development ○ customer enrollment ○ Local dispatch begins	• Ongoing: ○ customer enrollment ○ local dispatch	• Ongoing: ○ customer enrollment ○ local dispatch	• Ongoing, if necessary: ○ customer enrollment ○ local dispatch	• Ongoing, if necessary: ○ customer enrollment ○ local dispatch
Residential Solar and Battery Storage Adder Program	• Program design and launch • Mass marketing • customer enrollment • Local dispatch begins	• Ongoing: ○ mass marketing ○ customer enrollment ○ local dispatch	• Ongoing: ○ mass marketing ○ customer enrollment ○ local dispatch	• Ongoing, if necessary: ○ mass marketing ○ customer enrollment ○ local dispatch	• Ongoing, if necessary: ○ mass marketing ○ customer enrollment ○ local dispatch

Program	Major Activities				
	2026	2027	2028	2029	2030
Commercial Solar Adder Program	• Program design and launch • Marketing • business development • customer support begins	• Ongoing: ○ Marketing ○ business development ○ customer support	• Ongoing: ○ Marketing ○ business development ○ customer support	• Ongoing, if necessary: ○ Marketing ○ business development ○ customer support	• Ongoing, if necessary: ○ Marketing ○ business development ○ customer support
Commercial Battery Storage Program	• Customer stakeholdering, feedback • Program design and development	• Program Launch • Business development begins • customer engagement begins • Enrollment begins • BESS construction begins	• Ongoing: ○ business development ○ customer engagement • BESS construction continues	• Ongoing: ○ business development ○ customer engagement • Initial capacity available • Dispatch begins • Ongoing construction of additional capacity	• Ongoing: ○ business development ○ customer engagement ○ Capacity availability ○ Dispatch • Ongoing construction of additional capacity

1

2

3

b) Please refer to answers below, as well as Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report for the details requested.

i) Quantitative and qualitative benefits and costs associated with the distribution system are described and shown in Section 4 of Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report, which summarizes the Distribution Service Test (DST) methodology and results. Quantitative and qualitative benefits and costs associated with the Ontario electricity system are described and shown in Section 5 of the attached report, where a summary of the Energy System Test (EST) methodology and results are found.

ii) Refer to answers (a)(iii) and (b)(i) above.

iii) Refer to answer (b)(i) above. Hydro Ottawa notes that the DST results in Section 4 of Attachment 2-Staff-67(A) - NWCSP - BCA Summary Report demonstrate the cost effectiveness for the portfolio of six programs for the West 28kV (North) planning region. The process and analysis will be replicated for additional planning areas including the Core and West 13kV planning regions - as part of the NWS assessment process to confirm cost-effectiveness of the portfolio prior to execution.

c)

i) Hydro Ottawa is investigating potential collaboration with the IESO for the following programs (identifying the applicable Save On Energy Program for which collaboration is possible):

- Commercial Retrofit Incentive Adder Program
  - Save On Energy Retrofit Program
- Residential Demand Response Program
  - Save On Energy Peak Perks
- Commercial Demand Response (HVAC) Program
  - Save On Energy Commercial HVAC Demand Response Program
- Residential Solar and Battery Storage Adder Program
  - Save On Energy Home Renovation Savings Program
- Commercial Solar Adder Program
  - Save On Energy Retrofit Program

ii) Hydro Ottawa confirms the $2M/year funding request excludes potential IESO funding for each of the programs.

iii) For clarity, Hydro Ottawa is not initially requesting funding from the IESO to deliver NWCSP as the "Stream 2" funding mechanism does not yet exist. As described in Section 9.2.4.3 of Schedule 2-5-4 - Asset Management Process, Hydro Ottawa expects that there will be a transition to a mechanism allowing LDCs to access IESO funding for local programs - known as "Stream 2" local programs - to be released during this rate application period following the completion of an OEB consultation[1]. LDCs will be provided funding to deliver programs, which would supplement funding from rates requested within this filing. Given that system needs require Hydro Ottawa's immediate action and deployment of the NWCSP portfolio prior to the resolution of availability of Stream 2 funding, Hydro Ottawa has proposed a Non-Wires Solutions Variance Account to record the difference between projected and actual distributor NWS costs for all NWS projects, including the NWCSP, offset by any external funding, including from IESO. The approach is further described in Section 2.1 of Schedule 9-2-1 - New Deferral and Variance Accounts and in interrogatory response to 1-Staff-18.

iv) As stated in response (c)(iii) above, Hydro Ottawa is not initially requesting funding from the IESO to deliver NWCSP as the "Stream 2" funding mechanism does not yet exist. Hydro Ottawa is unable to speculate as to how the scope of the program would change at this time. Hydro Ottawa will consider the implications of the Stream 2 mechanism on design and scope of the NWCSP if and when it is required to do so.

d) In reference to the preamble, IESO's Local Achievable Potential Study (L-APS) is not complete and remains in progress at this time. The L-APS results may affect program design and/or program spending, however until results are obtained it would be speculative to suggest the potential impact. Should program deployment or funding allocations need to change as a result of the outcome, Hydro Ottawa would leverage the NWS Variance Account for any net difference between the estimated incentives built into the test year budget and actual incentives that are

[1]Ontario Energy Board, "OEB Consultation on Regulatory Framework for Local Energy Efficiency Programs" https://engagewithus.oeb.ca/nws_review/news_feed/oeb-consultation-on-regulatory-framework-for-local-energy-efficiency-programs

funded by the distributor, as described in 1-Staff-18 (a) to ensure transparency and effective management of funds.



Non-Wires Customer Solutions Program

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

Hydro Ottawa

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1. EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

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

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

1.1. RESULTS

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

Table 1 - BCA Results ($'000s)

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

1.1.1. Distribution Service Test Results

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

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

1.1.2. Energy System Test Results

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

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

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

2. METHODOLOGY

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

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

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

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

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

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

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

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

2.1. FORWARD-LOOKING UNCERTAINTY

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

2.2. DIFFICULT TO QUANTIFY AND QUALITATIVE IMPACTS

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

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

2.3. SYMMETRICAL TREATMENT

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

2.4. INCREMENTAL ANALYSIS

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

2.5. NET PRESENT VALUE/DISCOUNTED CASH FLOW ANALYSIS

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

2.6. DISCRETIONARY VS NON-DISCRETIONARY SYSTEM NEEDS

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

2.7. STUDY PERIOD

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

[9] OEB BCA Framework, p.13

2.8. TRANSPARENCY AND VALIDATION

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

3. DESCRIPTION OF DISTRIBUTION SYSTEM NEED BEING SERVED

3.1. REGION OVERVIEW

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

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

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

3.2. NWS PRE-ASSESSMENT

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

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

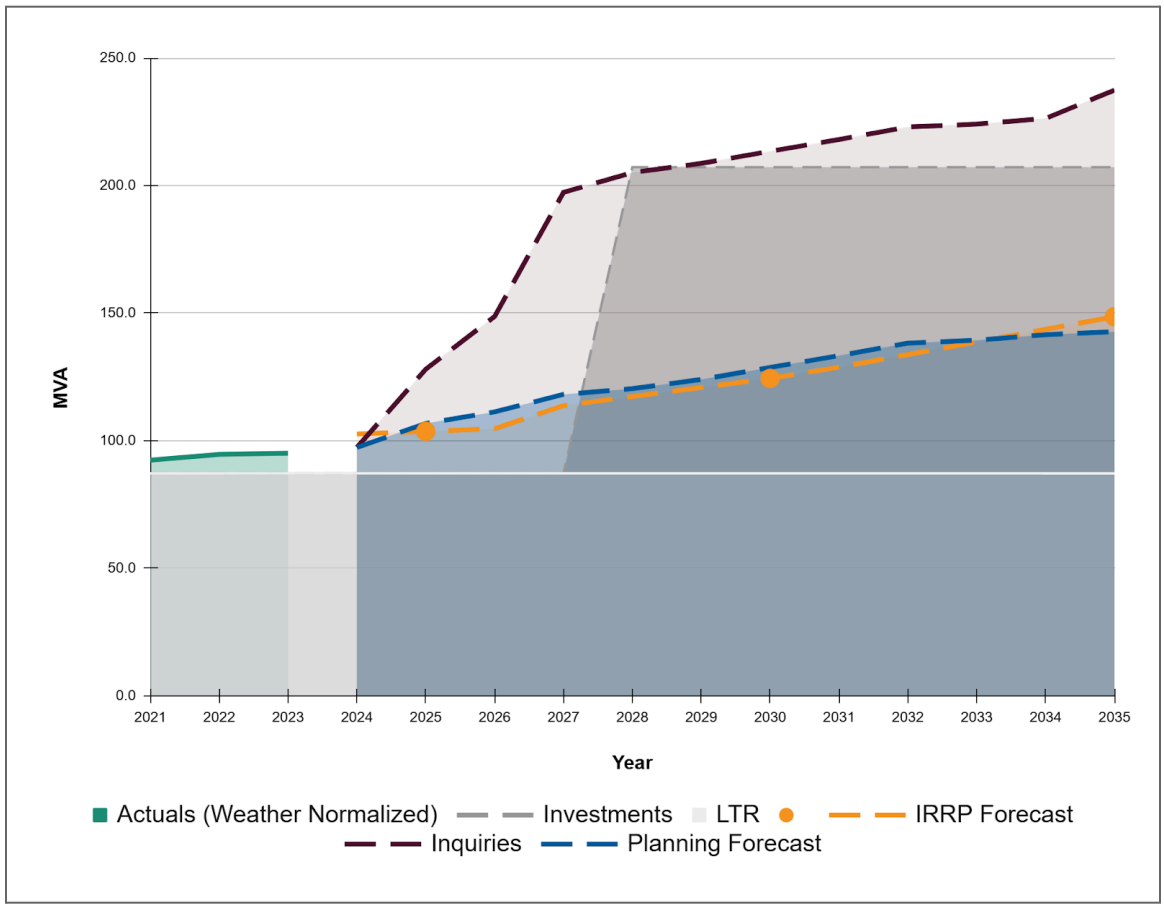
NWS Pre-Assessment Criteria						NWS Pre-Assessment Scenario?			NWS Pre-Assessment Scenario Pass?
Immediate Capacity Need?	Distribution Connected Station(s)?	Overload <7.5MVA by 2030?	Limited Connections?	IRRP Forecast overload by 2030?	Transmission Constraints?	Scenario 1	Scenario 2	Scenario 3	
✓		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

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

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

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

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



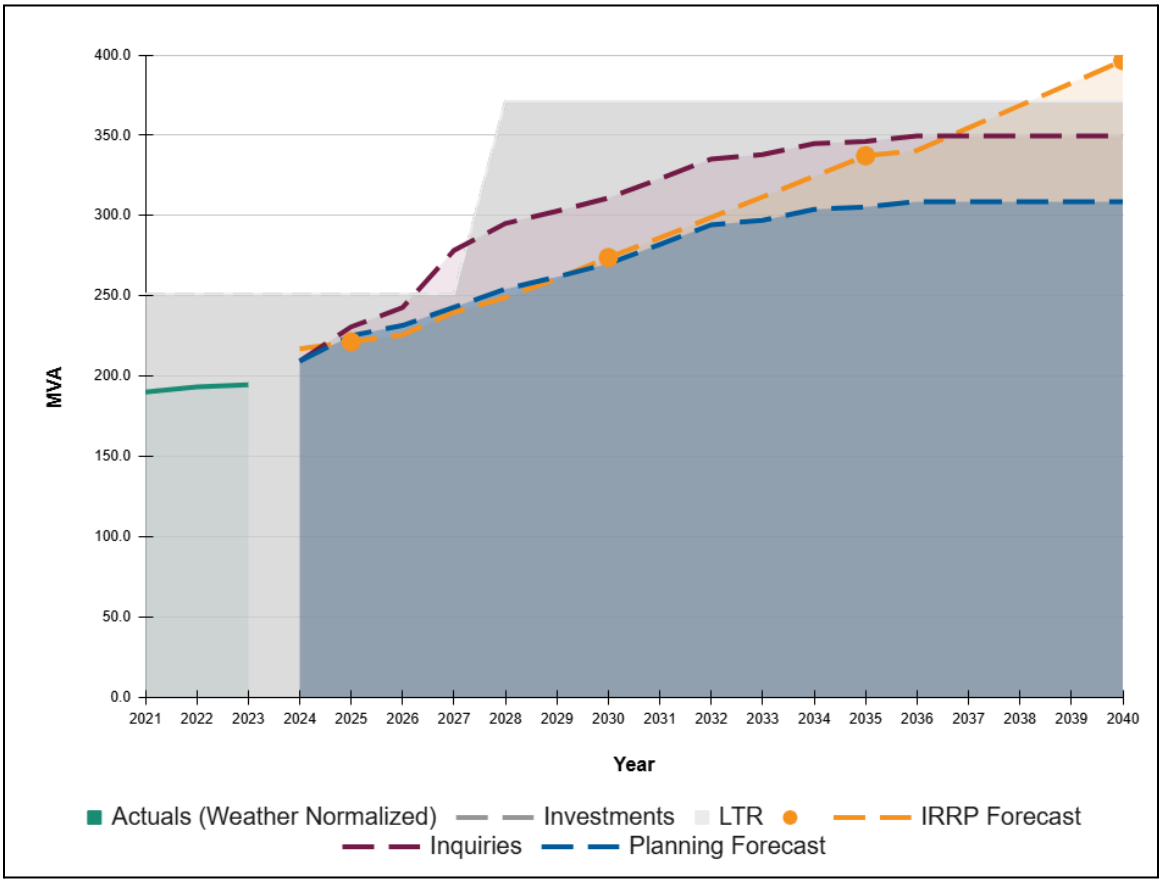
As per the forecasted demand shown in Figure 1, the need for a new station in this region is urgent and the proposed solution will ease capacity constraints and improve reliability of the West 28 kV (North) region upon energization in 2028. However, there still remains a capacity shortfall in the interim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

Scenario 3: Planning Regions Overloaded by 2030 / Transmission Constrained

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

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

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



3.3. NON-WIRES CUSTOMER SOLUTIONS PROGRAM PORTFOLIO

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

[10] See sections 6.4.1 and 6.4.3 of the IESO's Ottawa Area Integrated Regional Resource Plan, July 31, 2025
[11] The figure includes the following stations: "New" Kanata North (2028 energization), Kanata, Marchwood, Terry Fox, Janet King 28kV and Bridlewood 28kV. Janet King is part of the West 28kV region and supplies a small pocket of customers in the Stittsville area, with interconnections to Bridlewood and Terry Fox, but not Marchwood or Kanata. Therefore Janet King has been excluded for NWCSP deployment at this time.

Table 3 - NWCSP Portfolio

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

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

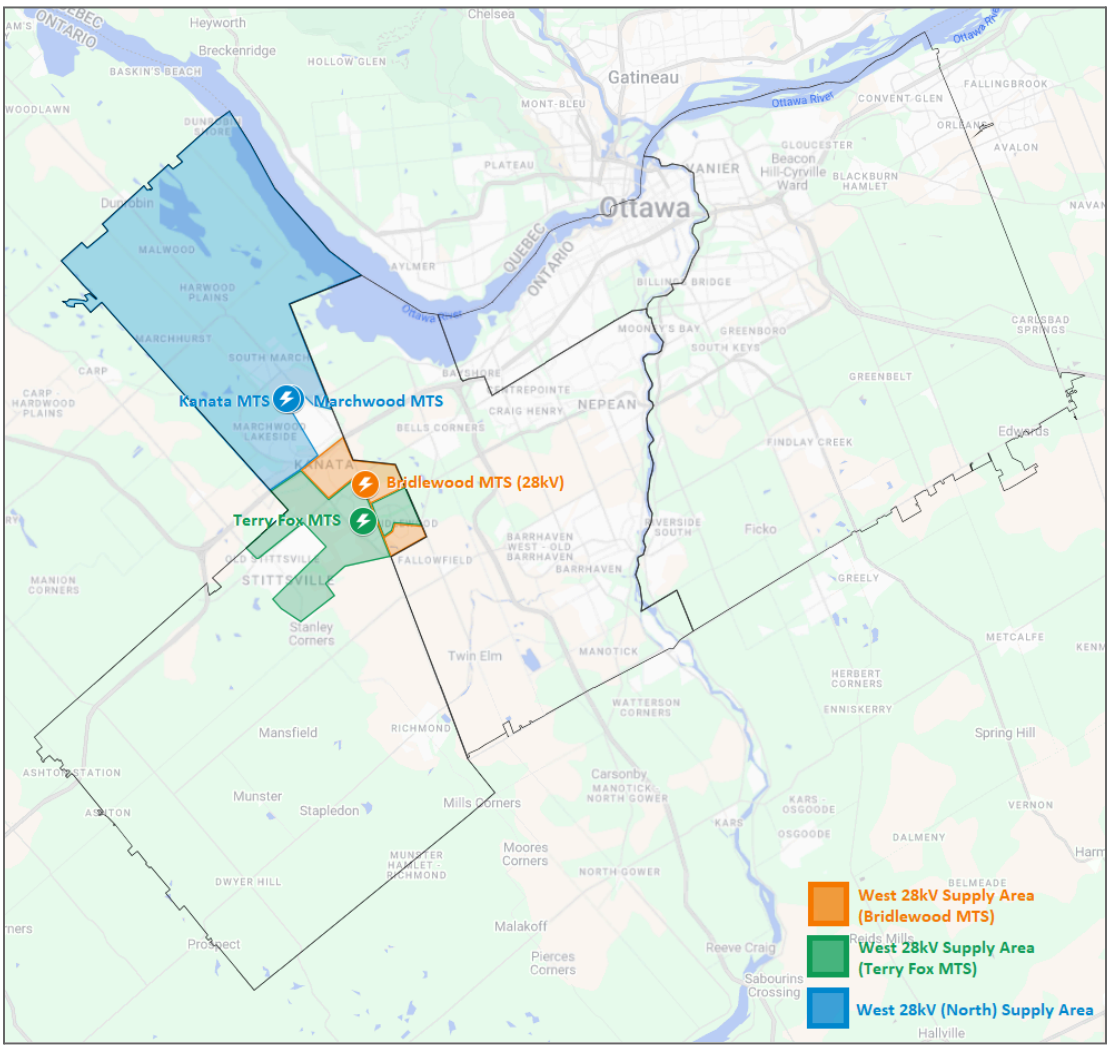
Further details and assumptions for each individual program can be found in section 4.2.2 of this report, as well as Appendix A.

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

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

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

Figure 3 - Kanata Region



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

Table 4 – Customer Count by Type (2024 Data)

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

4. DISTRIBUTION SERVICE TEST

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

4.1. REFERENCE CASE

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

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

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

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

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

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

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

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

4.2. QUANTITATIVE BENEFITS

4.2.1. Distribution Capacity Benefits

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

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

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

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

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

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

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

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

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

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

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

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

For the period of 2026 through 2028, the calculated benefit should be considered as an *avoided capacity benefit*, with the NWCSP acting in place of a traditional infrastructure solution by adding incremental short term capacity within the region. Beginning in 2029, and for the rest of the analysis period, the benefit should be

considered a *deferred capacity benefit*, with the incremental capacity helping to delay or defer the need to construct a *second* new station to serve the region in the mid 2030s.

4.3. QUALITATIVE BENEFITS

4.3.1. Reliability

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

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

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

4.3.2. Resilience

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

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

4.3.3. Innovation and Market Transformation

Given that the regulatory landscape around NWS is evolving in Ontario, there will be lessons learned for both Hydro Ottawa, IESO, the OEB, fellow distribution utilities and other stakeholders across the Ontario electricity

sector as a result of pursuit, design, and deployment of the NWCSP in this targeted area of need. The value associated with these lessons learned is difficult to quantify.

4.3.4. Planning Value

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

4.4. NON-WIRES SOLUTIONS COSTS

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

4.4.1. Participant / Host Costs / Benefits

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

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

4.4.2. Non-Wires Solution Acquisition Costs

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

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

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

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

Table 5 - Estimated Incentives

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

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

4.4.3. OM&A costs

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

4.4.4. Ancillary service costs

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

4.4.5. Program Costs - Summary

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

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

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

4.5. DST RESULTS

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

Table 7 - DST Results ($'000s)

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

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

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

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

4.6. DISTRIBUTION SERVICE TEST RISKS

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

4.6.1. Enrollment Risk - Likely

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

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

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

4.6.2. Coordination Risk - Likely

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

5. ENERGY SYSTEM TEST

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

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

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

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

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

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

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

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

5.2. TRANSMISSION CAPACITY (DEFERRAL OR AVOIDANCE BENEFIT)

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

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

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

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

5.3. AVOIDED COSTS - GENERATION CAPACITY

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

5.4. AVOIDED COSTS - ENERGY

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

5.5. NWS ACQUISITION COSTS - INCREMENTAL TO DST COSTS

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

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

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

5.7. EST RESULTS

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

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

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

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

5.8. ENERGY SYSTEM RISKS

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

6. PROPOSED APPROACH TO COST RECOVERY

6.1. NWS VARIANCE ACCOUNT

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

6.2. INCENTIVE MECHANISMS

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

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

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

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

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

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

	2026	2027	2028	2029	2030
Estimated DST Benefits	$ 297	$ 632	$ 783	$ 1,222	$ 1,282
Estimated DST Costs	$ 128	$ 251	$ 395	$ 695	$ 749
Estimated Net DST Benefits	**$ 169**	**$ 381**	**$ 388**	**$ 527**	**$ 533**
Estimated Net DST Benefits (Capped at value of estimated DST Costs)	**$128**	**$251**	**$388**	**$527**	**$533**
NPV of estimated Net DST Benefits	**$1,486**				
SSM (50%/50%)	**$743**				

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

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-68

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / pp. 287-288 (pdf Exhibit 2 Part 3, pp. 287-288)

Preamble:
In its application, Hydro Ottawa mentions the EV Everywhere project as an innovation pilot led by BlueWave-ai and funded in part by IESO's Grid Innovation Fund. Hydro Ottawa notes that the pilot is underway with learnings that will be leveraged in other initiatives like the Ottawa Distributed Energy Resources Accelerator (ODERA) project.

Hydro Ottawa also mentions installing two BESS solutions in early 2025 to provide a proxy of the impact of a future state with wider adoption of EVs with bi-directional energy flow.

QUESTION(S):

a) Please clarify if Hydro Ottawa is requesting any rate funding related to the EV Everywhere project from 2026 to 2030. If so, please provide the following details:
    i) The funding requested from rates for the EV Everywhere project per year
    ii) A detailed description of what the project entails, specifically including:
        i) The specific distribution system need that is being addressed
        ii) The investment category the project costs falls under
        iii) The qualitative and quantitative benefits (including avoided/deferred costs) and costs associated with the project as opposed to a corresponding traditional wires solution, if any
        iv) Any calculation support that Hydro Ottawa has carried out in assessing the cost-effectiveness of the project.

b) Please clarify the amount of funding that was provided by IESO's Grid Innovation Fund for the EV Everywhere Pilot and how the rest of the pilot was funded (e.g., source and amount of funding).

   i) Please confirm the status and validity of the funding (e.g., is the Grid Innovation Fund support assured for the life of the project?).

c) If no rate funding is being requested for the EV Everywhere project, please clarify whether the EV Everywhere pilot is still underway.

   i) If so, what does the project entail from 2026 to 2030, and what are the long-term distribution system cost implications of the project?

d) Please clarify if there is any connection between the 2 EV Everywhere BESS solutions to be installed in early 2025 and the 4 utility-owned BESS proposed as part of the 2026-2030 Custom IR application.

e) Please clarify if ODERA is a separate initiative or a continuation (e.g., Phase 2) of the EV Everywhere project.

RESPONSE(S):

Hydro Ottawa is participating in the EV Everywhere project led by BluWave-ai.

a) Hydro Ottawa is not requesting rate funding related to the EV Everywhere project from 2026-2030 as the project will conclude in 2025.

   i) Refer to part (a).

   ii) Refer to part (a).

b) As the EV Everywhere project is led by BluWave-ai, Hydro Ottawa does not have a contribution agreement with the IESO that clarifies the amount of funding that was provided by IESO's Grid Innovation Fund for the EV Everywhere Pilot. The IESOs website (accessed August 1) provides

Grid Innovation Fund Project Details[1]. However, these details do not outline how the rest of the project was funded.

Bluwave-ai has executed a contribution agreement with the IESO for the project, and Hydro Ottawa is supporting their work. Through Hydro Ottawa's agreement with the project lead (Bluwave-ai), Hydro Ottawa is entitled to receive $348.8k "in eligible costs related to procurement for the Project" less 17.5% for the Project Lead's administration costs.The Hydro Ottawa gross costs associated with the project (prior to reimbursements from the project lead) are approximately $900k. The source of Hydro Ottawa's contribution to the project are captured within the 2021 to 2025 investment plan under the Distribution Enhancements Capital Program within the System Service Investment Category and are funded by Phase 2 of the MiGen Program's $2.2M budget, under the 2021-2025 settlement agreement EB-2019-0261. See response to interrogatory 1-Staff 4 (a).

i) Hydro Ottawa cannot comment on the status and validity of the IESO Grid Innovation Fund support. The project lead has not provided any indication to Hydro Ottawa of concerns with respect to meeting the obligations of the contribution agreement.

c) The EV Everywhere project is on track to conclude by the end of 2025, and therefore no project activities or costs are expected from 2026 to 2030.

i) Refer to part (c).

d) There is no project connection between the EV Everywhere BESS and the 4 utility owned BESS proposed as part of the 2026-2030 Custom IR application. Hydro Ottawa will leverage the learnings from the EV Everywhere BESS for any future project involving a BESS.

[1] Independent Electricity System Operator, "Bluwave-Project Debrief"
"https://ieso.ca/-/media/Files/IESO/Document-Library/funding/Grid-Innovation-Fund/BluWave-project-brief.pdf

e) The ODERA project is a separate initiative from the EV Everywhere project. For a summary of how lessons learned from the EV Everywhere project will inform the ODERA project, refer to interrogatory response 2-Staff-69 part (e).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-69

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / pp. 288-289 (pdf Exhibit 2 Part 3, pp. 288-289)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 8 / pp. 98-99 (pdf Exhibit 2 Part 4, pp. 462-463)

Preamble:
In its application, Hydro Ottawa has identified ODERA as an NWS initiative. This was described as an innovative pilot in the Kanata North region, partially federally funded by Natural Resources Canada (NRCan) in March 2025. Hydro Ottawa notes this is a DER enablement initiative that is the "logical next step" following learnings from the EV Everywhere pilot.

QUESTION(S):

a) Please clarify if Hydro Ottawa is requesting any rate funding related to the ODERA project from 2026 to 2030. If so, please provide the following details:
    i) The funding requested from rates for the ODERA project
    ii) A detailed description of what the project entails, specifically including:
        i) The specific distribution system need that is being addressed
        ii) The qualitative and quantitative benefits (including avoided/deferred costs) and costs associated with the project as opposed to a corresponding traditional wires solution (if any),
        iii) Any calculation support that Hydro Ottawa has carried out in assessing the cost-effectiveness of the project.
b) Please clarify the amount of funding that was provided by NRCan for the ODERA project, and if NRCan was aware that additional funding would be requested from another source when funding was originally granted.

c) Outside of NRCan funding, how is/will the rest of the ODERA pilot be funded (e.g., source and amount of funding)?
d) Will the scope of the ODERA project change if additional funding from rates or external sources is not granted? If so, please describe how the pilot will change.
e) Please clarify which learnings from the EV Everywhere pilot were leveraged in the design of the ODERA project to justify why Hydro Ottawa believes it is the "logical next step."
    i) Does Hydro Ottawa envision another pilot/project to come out of the ODERA project? If so, what does that project entail?
f) Please file the contract between Hydro Ottawa and NRCan for the funding of the ODERA pilot project

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RESPONSE(S):

Hydro Ottawa notes that the evidence reference for the quotation in the preamble is p.39 of Section 2.4.4 of Schedule 1-4-1 - Customer Engagement Ongoing.

Hydro Ottawa would like to clarify that the ODERA project is not considered a Non-Wires Solution (NWS), but rather a technology project 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 and deploy NWS. For more details on ODERA, please refer to the project charter in Attachment 2-Staff-69(A) - ODERA Project Charter - REDACTED.[1]

a) Hydro Ottawa confirms rate funding is requested for the ODERA project.
    i) The amount requested from 2026-2030 rates is $5.1M within the Distribution Enhancements program under the System Service Investment Category. See Section 3 of Schedule 2-5-8 - System Service Investments.
    ii) ODERA intends to leverage advanced technology to enhance grid reliability and efficiency by optimizing asset utilization and mitigating capacity constraints. The project

[1] Please note that certain confidential information has been redacted in the ODERA Project Charter. The rationale for these redactions is outlined in Hydro Ottawa's confidentiality submission.

will be initially deployed in a targeted area of system need, Kanata North, more specifically, the West 28kV and West 28kV (North) planning areas. Please see part (a)(ii) of the response to interrogatory 2-Staff-67 for a map of the target area. The main objectives of the project, as outlined in the project charter, are as follows:

- Develop and pilot a system to predict the achievable load curtailment of customer-owned DERs, aggregated at both the transformer and feeder levels within the pilot area.
- Develop and pilot a system to localize distribution transformers and feeders at risk of electrical overload within the pilot area.
- Develop and pilot a system for the intelligent orchestration of customer-owned DERs, to effectively mitigate electrical overloads on distribution transformers and feeders within the pilot area.
- Drive customer participation in DER programs by identifying potential engagement barriers and developing a customer engagement strategy that prioritizes education, convenience, and value.
- Assess customer experience and satisfaction with participating in the DER pilot program through qualitative feedback.
- Document and broadly disseminate key findings, best practices, and lessons learned from this pioneering DER pilot project to foster industry-wide knowledge sharing.
- Evaluate the scalability and adaptability of the pilot project's technological solution for potential future deployment across the broader electricity grid.

iii) The ODERA project isn’t directly addressing a specific distribution system need, but rather aims to close a technology gap that currently impedes Hydro Ottawa's ability to effectively deploy Non-Wires Solutions (NWS) and manage Distributed Energy Resources (DERs) in its system. Indirectly, ODERA will support the system needs within the West 28kV and West 28kV (North) planning areas. Please refer to Sections 9.1.4.2.4 and 9.1.4.2.5 in Schedule 2-5-4 - Asset Management Process for further details.

The ODERA project is validating a technology enablement architecture, and therefore is not an NWS. As such, it cannot be compared to a traditional poles and wires investment. The project benefits include:

- Accelerating Hydro Ottawa's grid modernization plans to:
  - Improve asset utilization.
  - Increase reliability, resiliency, and flexibility.
  - Increase penetration of distributed energy resources (DER).
- Addressing capacity constraints and improving grid reliability in the deployment area.
- Demonstrating the role of an active electricity distribution system in a future electric system.
- Sharing project knowledge and insights to enhance and advance public awareness around flexible resources.
- Acquiring data and experience around customer behaviour and interest with regards to flexible resources.
- Learning about the techno-economic potential of flexible non-wires solutions to meeting grid needs.
- Improving customer accessibility to grid-integrated solutions.

A BCA has been completed for the proposed Non-Wires Customer Solutions Program in Kanata North. The positive results demonstrate the immediate need for the ODERA solution as this is a key component of Hydro Ottawa's ability to deliver the proposed programming. Further details of the Non-Wires Customer Solutions Program, including the BCA, can be found in response to interrogatory 2-Staff-67.

b) Hydro Ottawa has executed a contribution agreement with Natural Resources Canada (NRCan) to receive $6M in federal funding for the ODERA project. NRCan is aware that regulatory approval is required for Hydro Ottawa's portion of the project cost. The contribution agreement is conditional upon receiving rate funding approval for the requested funds and the federal funding entity has the ability to terminate the agreement if Hydro Ottawa is not successful in receiving rate funding support.

c) The balance of the ODERA project is proposed to be funded by rates.

d) Please refer to part b). Hydro Ottawa is unable to speculate as to how the scope of the project would change in the absence of rate funding. Hydro Ottawa will consider the implications of not having rate funding for this project if and when it is required to do so. Please also see response to part b).

e) As described in Section 9.2.4.1 of Schedule 2-5-4 - Asset Management Process, the EV Everywhere project has and continues to inform the ODERA project. Learnings from EV Everywhere have included:

- Determining how to accurately forecast the available capacity from EV's.
- Understanding the necessary coordination to effectively communicate with EV users for curtailment events.
- Supporting development of necessary standards for field evaluation and commissioning of BESS.
- Understanding the communication protocols, data management, visibility and cybersecurity requirements for effective BESS integration.

The ODERA project builds on the above. It will enable dispatch of a wider array of DER devices beyond electric vehicles, including smart thermostats and battery energy storage systems to understand how the orchestration of different devices can help address grid constraints and system reliability challenges. Additionally, leveraging insights on forecasting capacity, the project aims to develop a solution to predict potential overloads at the distribution transformer level which can be rolled up to predict asset performance at higher levels. All of the above is necessary to further advance Hydro Ottawa's requisite internal systems and processes to facilitate the enablement of flexible Non-Wires Solutions.

i) An objective of the project is to evaluate the scalability and adaptability of the project's technological solution for potential future deployment across the broader electricity grid.

f) Please see Attachment 2-Staff-69(B) - ODERA Contribution Agreement - REDACTED.[2]

[2] Please note that certain confidential information has been redacted in the ODERA Contribution Agreement. The rationale for these redactions is outlined in Hydro Ottawa's confidentiality submission.

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HydroOttawa

Ottawa Distributed Energy Resource Accelerator (ODERA)

Project Charter

March 24, 2025

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Project Name	Ottawa Distributed Energy Resource Accelerator (ODERA)		
Project No.	9202016181		
Author	Andrzej Tomalik	Date	Mar 18, 2025

1. PROJECT OVERVIEW

PROJECT DEFINITION AND BACKGROUND

Hydro Ottawa Limited (HOL) is embarking on a pilot initiative to develop an integrated network of Distributed Energy Resources (DERs) in Ottawa, with the support from Natural Resources Canada (NRCan).

The Ottawa DER Accelerator (ODERA) Project aims to advance the use of Demand Response (DR) to manage DERs such as customer-owned smart thermostats, electric vehicle chargers and battery storage. The project seeks to address a gap in the current smart grid landscape, where there is limited visibility on granular asset loading (distribution transformers) and no ability to respond to potential overload events at specific distribution assets or nodes.

The Project intends to leverage advanced technology to address grid constraints and system reliability challenges. The Project will make meaningful steps to leverage DR to incentivize residential customers to enroll their DERs and other devices in a targeted resource- and asset-constrained (Transmission & Distribution) community, Kanata North (~36k customers, 5.5k distribution transformers, with lower-than-average system reliability 2020-2024: 9.5% of SAIDI, 6.3% of SAIFI, 18.5% of equipment failure).

The accelerating pace of load growth combined with deteriorating equipment and the availability of new technologies require new approaches to grid planning and operations to reduce demand peaks and to maintain and improve grid reliability, grid resilience, cost effectiveness, and customer experience. HOL is investing in strategic system observability and controllability capabilities and adaptation of its enterprise data and communications platforms, to integrate near real-time data to infer grid performance. This will facilitate forecasting of potential overloading at the distribution transformer level which can be rolled up to predict asset performance at higher levels. This information can be used to inform the usage of DERs and DR schemes to curtail load in an effort to minimize impacts on the distribution system down to the distribution transformer level.

The proposed solution will align with Hydro Ottawa's cybersecurity standards in its development and will help to support HOL's planning process, and daily operations.

This project aims to develop and test the integration of advanced technologies, increasing the maturity to Technology Readiness Level (TRL) 8: ("Actual technology proven through

successful deployment in an operational environment"), while enhancing grid flexibility in a constrained region.

Additionally, the lessons learned through this project will provide a source of knowledge for the utility sector and support further development of technological solutions to enable electrification. The lessons will provide insights into how technology can facilitate cost-effective system improvements via customer-owned non-wires solutions. Knowledge dissemination will be a key part of the Project to ensure the lessons learned are effectively shared with stakeholders across the utility sector.

OBJECTIVES

The main objectives of the ODERA Project are to:

1. Develop and pilot a system to predict the achievable load curtailment of customer-owned DERs, aggregated at both the transformer and feeder levels within the pilot area.
2. Develop and pilot a system to localize distribution transformers and feeders at risk of electrical overload within the pilot area.
3. Develop and pilot a system for the intelligent orchestration of customer-owned DERs, to effectively mitigate electrical overloads on distribution transformers and feeders within the pilot area.
4. Drive customer participation in DER programs by identifying potential engagement barriers and developing a customer engagement strategy that prioritizes education, convenience, and value.
5. Assess customer experience and satisfaction with participating in the DER pilot program through qualitative feedback.
6. Document and broadly disseminate key findings, best practices, and lessons learned from this pioneering DER pilot project to foster industry-wide knowledge sharing.
7. Evaluate the scalability and adaptability of the pilot project's technological solution for potential future deployment across the broader electricity grid.

The electricity sector is rapidly transforming due to electrification and climate change initiatives, leading to increased demand for DERs that will need to be integrated in a way that enhances flexibility and resilience. This leads to greater complexity in planning and dispatching resources. The key drivers for the project are centered around modernization of the grid addressing identified gaps:

- Limitations in grid resilience and flexibility constrain the ability to respond to the uncertain pace of electrification-related demand and customer DER adoption.
- Limited intelligence available for management of grid assets and load peaks,
  - Limited visibility into existing DERs within Hydro Ottawa system,
  - No existing capability for managing curtailment prediction data.
    - No existing capability for granular real-time monitoring of the distribution assets down to distribution transformer level,

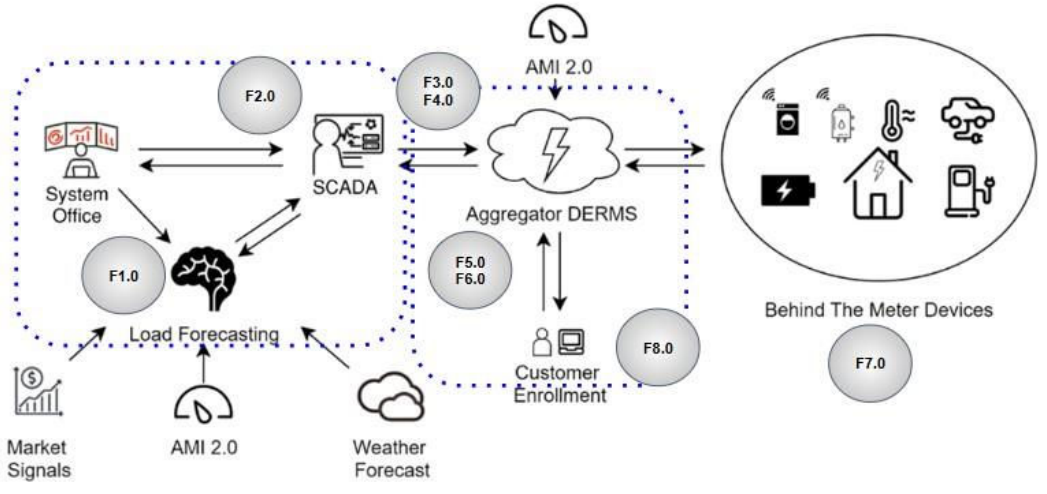
- An established OEB framework that promotes reactive instead of proactive deployment of infrastructure focused on affordability and necessity,
- A lack of granular grid control to handle distribution level constraints,

Traditional grid infrastructure offers limited visibility on granular distribution level asset loading, and no ability to predict and prevent overload events. The proliferation of smart, behind-the-meter customer-controlled devices including electric vehicles (EVs), battery storage, thermostats, heat pumps, and hot water heaters presents an opportunity for the availability of real-time load intelligence that can be used for accurate load forecasting and for curtailing the load to avoid detrimental events including blackouts and equipment damage.

Leveraging customer-owned DERs is a transformative step for utilities to improve grid flexibility, reliability, and efficiency, while also engaging customers as key partners in this evolving energy landscape. HOL's approach prioritizes educating customers and gradually integrating them into an active distribution grid, alongside necessary infrastructure upgrades.

2. PROJECT SCOPE

The diagram in Figure 1 shows the preliminary high-level concept of the ODERA system divided into functional blocks:



F1.0 - Load Prediction & Forecasting	**F2.0** - Curtailment Scheduling & Initiation	**F3.0** - DER Grouping at Distribution Transformer Level	**F4.0** - Secure 2-Way System Communication
F5.0 - DER Aggregation & Management	**F6.0** - Predict DER Curtailment Potential	**F7.0** - Household Smart Device Management	**F8.0** - Customer Enrollment & De-Enrollment

Figure 1: ODERA Preliminary High Level System Concept

The scope of the project includes the development of a solution to meet the project objectives. It is important to note that the functional flow block diagram presented in Figure 1 is the preliminary concept and will be reviewed by the project team members and is subject to

revision based on feedback and further analysis. An overview of the plan to accomplish each of the project objectives is provided in Table 1. Refer to the *ODERA Schedule* for the detailed execution plan:

Table 1: Project Objectives & Execution Strategy

Objective 1: Develop and pilot a system to predict the achievable load curtailment of customer-owned DERs, aggregated at both the transformer and feeder levels within the pilot area.
• Create a requirement specification to identify requirements for DER aggregation. • Engage a DER aggregation partner to achieve the identified requirements. • In collaboration with the DER aggregation partner, identify eligible behind-the-meter devices for the ODERA Program. • Develop and implement a mechanism for the association of Distributed Energy Resources (DERs) with their respective distribution transformers to enable load curtailment prediction by distribution transformer • Develop, test and validate a network model for the pilot area linking civic addresses to distribution transformers to facilitate distribution transformer level aggregation and control. • Aggregate customer behind-the-meter devices to the distribution transformer level allowing roll up to higher levels such as the feeder level.
Objective 2: Develop and pilot a system to localize distribution transformers and feeders at risk of electrical overload within the pilot area.
• Create a requirements specification to identify requirements for load forecasting. • Review different solutions based on their compliance to the requirements specification including review of vendor offerings and determine the best path forward. • In coordination with the selected vendor(s) configure the load forecasting module based on the requirements specification. • Design data architecture and communications infrastructure enhancements to collect data from revenue meters, field sensors, historical load data, and external factors such as weather to support load predictions. • Execute subsystem level verification testing and integrate the load prediction subsystem with data inputs, and other subsystems for system level verification testing. • Explore options for deployment of extra field sensors to improve load predictions.

Objective 3. Develop and pilot a system for the intelligent orchestration of customer-owned DERs, to effectively mitigate electrical overloads on distribution transformers and feeders within the pilot area.
• Create a requirements specification to identify requirements for curtailment scheduling • Review different solutions based on their compliance to the requirements specification including review of vendor offerings and determine the best path forward. • In coordination with the selected vendor(s) configure the curtailment scheduling subsystem based on the requirements specification. • Develop secure interfaces with the DER aggregator subsystem to collect distribution transformer level curtailment predictions and send curtailment schedules. • Develop secure interfaces with the load forecasting module to identify assets at risk of overload (distribution transformer, feeder, etc.). • Potential development of a secure interface with AMI2.0 to facilitate resource deployment triggering with near-real time load data. • Execute subsystem level verification testing and integrate with data inputs, and other subsystems for system level verification testing. • Assess load forecast accuracy against actual loading at the end of the technology pilot to quantify load forecasting model performance.
Objective 4. Drive customer participation in DER programs by identifying potential engagement barriers and developing a customer engagement strategy that prioritizes education, convenience, and value.
• Create an incentives program to encourage participation in the ODERA Program and launch a marketing campaign. • In collaboration with the DER aggregator partner, facilitate customer enrollment and participation in the ODERA program. • Determine the technical and contractual viability of collaborating with IESO's Peak Perks platform, and other applicable incentive programs, ensuring optimal customer experience and clear communication of customer and Dx/Tx benefits • Establish clear and transparent DER program brand, enrollment campaign, customer rewards, detailed privacy policy, and comprehensive program communications with customers. • In collaboration with DER Aggregation vendor, develop a simplified and user-friendly program enrollment process and interface, focusing on a frictionless onboarding experience. Leverage tools and meter data to segment, target and market to customers, gain support and drive enrollment through targeted marketing communications that consider community engagement and feedback loops.

- Thoroughly address customer concerns with participation in the program including, but not limited to providing detailed information about privacy and data handling procedures, device control options, and establishing trust through partnerships with trusted entities.
- Establish an incentives program, including a clear structure for payment(internal or external), and communicate these incentives transparently with specific details about how they will benefit each customer segment.

Objective 5. Assess customer experience and satisfaction with participating in the DER pilot program through qualitative feedback.

- Develop a customer feedback collection timeline and cadence in order to collect feedback at various stages of the pilot program.
- Develop a multi-channel feedback system such as online customer surveys, email addresses, and leveraging the DER Aggregation vendor where feasible to gauge customer feedback, sentiment, and opportunities for improvement.
- Develop training materials for staff on program inquiries, collecting feedback, addressing concerns and providing support.
- Develop a process for analyzing and reporting feedback.
- Create specific customer personas/segments within the program to provide more nuanced and actionable insights.

Objective 6. Document and broadly disseminate key findings, best practices, and lessons learned from this pioneering DER pilot project to foster industry-wide knowledge sharing.

- Create and maintain a robust project knowledge base including project plans, decisions records, lessons learned, risks, design inputs, and outcomes.
- Design and execute customer surveys.
- Develop whitepapers.
- Attend conferences.
- Share information with community associations.
- Launch news releases. Publish customer newsletters.
- Create other media.

Objective 7. Evaluate the scalability and adaptability of the pilot project's technological solution for potential future deployment across the broader electricity grid.

- Develop a grid wide deployment plan.
- Develop knowledge sharing and mobilization plans.

The following items are considered Out-of-Scope for this project:

- **Automated Curtailment Execution:** Solution shall only execute curtailment activities based on curtailment requests provided by a human from HOL (this request can be provided digitally).
- **Advance Distribution Management System (ADMS) Implementation:** The project will not be responsible for ADMS implementation (outside of providing requirements and testing the solution to the requirements) in the event it is selected as an option for any of the required subsystems.
- **Grid Wide Deployment:** The project will only focus on technology deployment in the Kanata North region identified.
- **Commercial DERs:** Although the solution considered should be capable of integrating commercial DERs and managing enterprise resources, the design, test and implementation of this type of solution is not within scope of this project.
- **Distribution Power Flow (DPF)**: This project will propose a Load Forecasting technique to predict overload events, but will not create a real time predictive modifiable model for executing DPF studies.

BENEFITS

This project will create new value for customers, foster greater engagement, and optimize the use of DERs to enhance grid operations as energy density increases, enabling us to deploy a combination of solutions to meet customers' capacity needs. The anticipated benefits of the DER Aggregation Pilot Project include:

Benefits to Canadians

- Accelerates grid modernization to:
  - Better utilize electricity system assets
  - Increase reliability, resiliency, and flexibility
  - Increase penetration of distributed energy resources (DER)
- Sets a technical and financial precedent for other electric utilities in developing their business beyond poles and wires
- Demonstrates the role of an active electricity distribution system in a future electric system
- Lays the groundwork for a more reliable and resilient electricity system
- Explores alternative approaches to meeting grid needs at lowest cost
- Share knowledge and insights to enhance public awareness
- Paving the way for nationwide grid modernization.

Benefits to Stakeholders

- Explore the techno-economic potential of non-wires solutions to meeting grid needs in the goal of exerting downward pressure on electricity rates,
- Provides data and experience on customer behaviour. This is significant for the Canadian electricity sector as electric load continues to grow,
- Improve customer accessibility access to grid-integrated solutions,
- Explore new business models for electricity system stakeholders,

- Provides customers an opportunity to participate in the electricity market.
- Address capacity constraints in the deployment region and improve grid reliability.

While the energy transition will require new ways to plan, build, and operate the grid, it also presents an opportunity to enhance customer value by offering products and services designed to make the transition easier and more convenient for customers by:

- **Deferring the need for major distribution and transmission infrastructure in targeted areas until absolutely necessary**, allowing more time to validate growth projections and preventing overbuilding that would negatively impact customer bills.
- **Minimizing the early replacement of existing assets due to rapidly increasing demand**, leveraging added functionality from emerging technologies, and slowing capital investments that could increase customer costs.
- **Extending the lifespan of current assets by managing load within rated limits**, reducing both the frequency and duration of outages.
- **Enhancing outage response flexibility**, such as enabling curtailment to temporarily switch feeder sections, thus reducing outage frequency and duration for customers.
- **Incorporating more granular customer data into planning** and exploring innovative solutions to meet growing customer demand for capacity.
- **Increasing customer engagement and providing incentives** by enabling the use of customer resources through demand response programs.

SUCCESS CRITERIA

The high-level success criteria are:

- Peak Load Reduction of 1.6 – 3.2 MW (1-2kW per enrolled device)
- Successful attainment of all project objectives.

To meet NRCan's requirements, the project will develop, track, and communicate Key Performance Indicators (KPIs) across four main categories:

1. Operational performance and business impact
2. Customer performance and impact
3. Knowledge dissemination
4. Longitudinal outcomes

The success of the project shall be measured in the following categories:

- **Technical Performance:** Advance the Technology Readiness Level (TRL) from level 5 to level 8-9. The technology will be gauged based on the solution's accuracy in:

- generating accurate load forecasts,
- predicting curtailment potential,
- effectiveness in controlling and managing DERs to achieve load reduction targets, and
- contribution to the improvement of outage frequency and duration for customers in the pilot area.

- **Equipment Performance:** Extend asset lifetimes by reducing equipment strain through enhanced monitoring and analysis of distribution transformers in the targeted area to quantify the technology's impact on extending asset lifespan and avoiding early replacement. The following will be monitored:

  - Average transformer loading trends, comparing historical data with data collected during the project period. Since transformers are not equipped with intelligent monitoring, we will rely on historical meter data from homes served by the transformers in the target area. This data will also contribute to the forecasting analytics engine.
  - Peak transformer loading trends, comparing historical data with data collected within the project window.
  - The ability to mitigate equipment strain through load peak shaving, leveraging the technology we are developing.
  - The number of transformers replaced, including the reason for failure and an analysis of their loading characteristics leading up to the point of failure.

- **Integration Success:** The solution's ability to seamlessly integrate with Hydro Ottawa's existing systems, including the Enterprise Service Bus and Advanced Metering Infrastructure (AMI), while satisfying strict cybersecurity requirements.

- **Customer Engagement:** Enroll 1,000 smart thermostats, 500 electric vehicles (or L2 chargers combined), and 100 residential energy storage systems in the demand response program. Customer engagement metrics will be developed with consideration for:

  - Number of customers by class, % and total MW of capacity forecasted and achieved from the program
  - Number of devices by category that are enrolled
  - Aided Awareness: A measure of a customer's awareness of the project and opportunity to participate in it.
  - Promoter Score: how the customer describes their experience and their willingness to share with others
  - Retention Rate: the percent of participants who stay enrolled in the program

- Engagement Rate: the percent of participants who opt-out of individual events, or measuring their interaction with the platform over time, or their response rates to participation surveys
- Customer Contributing Value: quantitative - how much value the customer's DERs have provided for DER calls (min., max., avg., and participation/dependability factor).
- Customer Derived Value: quantitative / qualitative - what does the customer state the value is with their participation and what they gain from participating

- **Compliance and Safety:** The solution's adherence to all relevant legal, regulatory, and safety requirements.

- **Project Management:** Timely delivery of project deliverables and adherence to project timelines.

- **Financial Performance:** The solution's overall cost-effectiveness and value for money.

3. PROJECT APPROACH

ASSUMPTIONS

- **Customer Participation:** The project scope assumes sufficient customer participation to obtain statistically significant results.
- **Data Availability:** The solution design assumes that real-time data collection (through AMI 2.0, for example), will become available and can be integrated into the solution at a later stage.
- **Technology Availability:** The project budget and schedule assumes that the ADMS will be implemented in advance of the integration date. It is understood that this assumption is now incorrect, and a budget and schedule update will be necessary, once the best direction is selected.
- **Partner Participation:** Hydro Ottawa will secure a contract with a DER aggregator platform provider and enhance the platform to meet project requirements.
- **Technology Capability:** The load forecaster and DR trigger platform will be developed to accurately forecast asset overloading and nodal constraints, and, together with DER aggregator, can be advanced to TRL 9.
- **System Integration:** Partner platforms will be successfully integrated with the utility platform.
- **Regulatory Approvals:** The project will secure the necessary regulatory support and approvals, including approval for AMI 2.0 deployment, with a priority on its installation in the target area.

CONSTRAINTS

- **Time Constraints:** The project timeline is defined in the milestones section below.
- **Scope Constraints:** Project scope is defined in section above and shall follow the key intent and motivation of the project as set forth in this document.
- **Resource Constraints:** The project is constrained by the availability of human resources and capital from Hydro Ottawa and partners as defined in sections below.
- **Regulatory and Legal Constraints:** The solution must comply with all relevant Canadian federal and Ontario provincial laws and regulations, particularly those related to privacy and data security.

DELIVERABLES

Project deliverables shall be developed to address the complete set of functional solution blocks identified in the project scope section above and shall be further refined in the project plan. A set of deliverables shall be developed to satisfy the reporting requirements as set out in the NRCan Contribution Agreement.

The main project deliverables will include:

- **Preliminary Design Document:** Initial documentation of proposed solutions, including solution interfaces, architecture, and data flow.
- **Detailed Design Document:** Detailed documentation of the proposed solution, including configuration parameters and enhancements based on the preliminary design:
    - Enhanced DER aggregator platform capable of managing and dispatching DR signals to customer-owned DERs at a granular level, o Data architecture and communications infrastructure enhancements to acquire and consolidate data around customer DERs, revenue meters, servicing transformers, and upstream current sensors,
    - Load forecaster & DR trigger platform capable of forecasting potential overloads and dispatching DR signals to specific customer-owned DERs to prevent detrimental outcomes,
    - Integrated partner platforms with utility platform,
- **Customer Enrollment Platform:** A platform to facilitate customer enrollment in the pilot area.
- **Integrated Load Forecasting, DER Aggregator, and Curtailment Scheduling System:** An integrated and functional solution.
- **Customer Value Metrics:** Develop metrics to demonstrate improvements to customer value including, but not limited to, outage frequency and duration, customer satisfaction, and participation rates.
- **Design Verification & Test Document:** Documentation of solution testing procedures and results:

- Validated network model and corrected erroneous data,
- Validated forecasting of asset overloading and nodal constraints,
- Tested use cases,
- Refined partner platforms,

- **Pilot Deployment Document:** Documentation of lessons learned and pilot deployment results, including details about enrolled participants. ○ Developed commercialization and operationalization plans, ○ Enrolled new distribution variable capacitors, FCIs, and other field deployed metrology (sensors),
- **Grid Wide Deployment Assessment & Plan:** Development of a plan which assesses the feasibility for grid wide deployment and a high level plan for deployment.
- **Knowledge Sharing:** Successful dissemination of project learnings and best practices to internal staff, customers, and other industry stakeholders.
- **Monthly Project Status Updates:** Regular updates on the project's progress.

MILESTONES

Refer to the project plan *ODERA Schedule* for a detailed execution plan.

Table 2: Project Milestones by Phase

Event	Start Date	Completion Date
Project Initiation	Sep 3, 2024	Mar 28, 2025
Scope of work development	Apr 4, 2025	Jul 29, 2025
Vendor Selection	Apr 7, 2025	Jul 31, 2025
Aggregator DERMS go live		Nov 18, 2026
Preparation Report to NRCan		Dec 31, 2025
Preliminary Design	Mar 31, 2025	Jan 12, 2026
Marketing and Knowledge Dissemination	Apr 4, 2025	Jun 14, 2028
Detail Design and Development	Jan 13, 2026	Nov 11, 2026
Detailed Design and Development report to NRCan		Oct 19, 2026
Design Verification and Test	Nov 12, 2026	Mar 8, 2027
Testing and AMI 2.0 deployment report to NRCan		Feb 10, 2027

Event	Start Date	Completion Date
Pilot Deployment	Mar 8, 2027	Apr 5, 2028
Technology Pilot Deployment report to NRCan		Mar 31, 2028
Integrated DERMS go live		Apr 6, 2027
NRCan Final Report		March 31, 2028
Project Closeout	Jan 24, 2028	Jun 14, 2028

4. PROJECT FUNDING

HUMAN RESOURCE COSTS

The project will utilize the following internal resources to accomplish the objectives:

Table 3: Project Human Resource Costs

Project Phase / Division	Start	Finish	Hours	Cost
Project Initiation	**Tue 9/3/24**	**Fri 2/14/25**	**242.4**	**$ 28,360.80**
CEDO			88.48	$ 5,672.16
CITO			44.24	$ 2,836.08
CCO			66.36	$ 4,254.12
Ancillary Support			44.24	$ 2,836.08
Preliminary Design	**Mon 2/17/25**	**Tue 3/10/26**	**7179.6**	**$ 840,013.20**
CEDO			2323.6	$ 271,861.20
CITO			2400	$ 280,800.00
CCO			2216	$ 259,272.00
Ancillary Support			240	$ 28,080.00
Detailed Design & Development	**Wed 3/11/26**	**Tue 1/26/27**	**27606**	**$ 3,229,902.00**
CEDO			7238	$ 846,846.00
CITO			18408	$ 2,153,736.00
CCO			1840	$ 215,280.00
Ancillary Support			120	$ 14,040.00
Design Verification & Test	**Fri 1/8/27**	**Mon 5/3/27**	**6951.2**	**$ 813,290.40**
CEDO			3295.2	$ 385,538.40
CITO			2800	$ 327,600.00
CCO			776	$ 90,792.00
Ancillary Support			80	$ 9,360.00
Technology Pilot Deployment	**Tue 5/4/27**	**Wed 5/31/28**	**6472.88**	**$ 757,326.96**
CEDO			1248.88	$ 146,118.96

Project Phase / Division	Start	Finish	Hours	Cost
CITO			2800	$ 327,600.00
CCO			2264	$ 264,888.00
Ancillary Support			160	$ 18,720.00
Project Close Out	**Thu 3/23/28**	**Wed 5/31/28**	**672**	**$ 78,624.00**
CEDO			368	$ 43,056.00
CITO			120	$ 14,040.00
CCO			120	$ 14,040.00
Ancillary Support			64	$ 7,488.00
Marketing & Knowledge Dissemination	**Tue 9/3/24**	**Mon 1/24/28**	**2732.8**	**$ 319,737.60**
CEDO			480	$ 56,160.00
CITO			320	$ 37,440.00
CCO			560	$ 65,520.00
Marketing			1292.8	$ 151,257.60
Ancillary Support			80	$ 9,360.00

VENDOR COSTS

Below is a list of planned expenses related to material costs and contracting services. In-kind contributions and software fees to the vendor are listed under “Other Vendor Expenses”.

Table 4: Project Vendor Costs

Vendor Activity	Contract Services	Material Costs
Preliminary Design	[redacted]	[redacted]
Aggregator design and development	[redacted]	
Travel Costs	[redacted]	
Detail Design	[redacted]	[redacted]
Aggregator Integration	[redacted]	
DERMS & Load Module Technical Development	[redacted]	
Historian Integration	[redacted]	[redacted]
Travel Costs	[redacted]	
Verification and Test	[redacted]	[redacted]
DERMS & Load Module	[redacted]	

Vendor Activity	Contract Services	Material Costs
Travel Costs	[redacted]	
Technology Pilot	[redacted]	[redacted]
DER Aggregator	[redacted]	
Installation AMI 2.0		[redacted]
Marketing Production	[redacted]	[redacted]
Webpage development	[redacted]	
Drip (educational) emails	[redacted]	
Targeted Ads	[redacted]	
Video production	[redacted]	
Targeted Bill Inserts & Direct Mail	[redacted]	
Translation of Marketing assets	[redacted]	
Marketing Launch	[redacted]	[redacted]
Publish Targeted Ads	[redacted]	
Targeted Bill Inserts & Direct Mail	[redacted]	
Translation of Marketing assets	[redacted]	
Marketing Support	[redacted]	[redacted]
Whitepapers / Knowledge Dissemination	[redacted]	
News Release	[redacted]	
Translation of Marketing assets	[redacted]	
Conferences	[redacted]	
Other Vendor Expenses	[redacted]	[redacted]
DER Aggregator (2025-2026)	[redacted]	[redacted]
DER Aggregator (2026-2027)	[redacted]	[redacted]
DER Aggregator (2027-2028)	[redacted]	[redacted]
DERMS (2026-2027)		[redacted]
DERMS (2027-2028)		[redacted]

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FINANCIAL SUMMARY

Review and approvals of project expenditures and performance shall follow existing HOL financial policies.

Total Project Cost	$ 14,638,123.63
NRCAN Grant	$ (6,000,000.00)
In-kind Contributions	$ (360,500.00)
Hydro Ottawa contribution	$ 8,277,623.63

Table 5: Project Total Cost Summary

Project Phase / Activity	Labour Cost	Contract Services	Material Costs	Total Cost
Project Initiation	[redacted]			**$ 28,360.80**
Preliminary Design	[redacted]	[redacted]		**$ 1,734,113.20**
Detailed Design & Development	[redacted]	[redacted]	[redacted]	**$ 4,753,402.00**
Design Verification & Test	[redacted]	[redacted]		**$ 965,110.40**
Technology Pilot Deployment	[redacted]	[redacted]	[redacted]	**$ 4,079,826.96**
Project Close Out	[redacted]			**$ 78,624.00**
Marketing & Knowledge Dissemination	[redacted]	[redacted]		**$ 449,237.60**
Software Annual Fees			[redacted]	**$ 800,000.00**
Program Incentives		[redacted]		**$ 1,749,448.67**
Total:	$ 6,067,254.96	$ 4,320,868.67	$ 4,250,000.00	**$ 14,638,123.63**

Table 6: Project Annual Cost Summary

	2024	2025	2026	2027	2028	Total
Labour	$ 23,577.40	$ 837,800.71	$ 3,381,357.69	$ 1,425,605.91	$ 398,912.73	**$ 6,067,254.96**
Labour.1-General	$ -	$ 66,924.00	$ -	$ -	$ -	**$ 66,924.00**
Labour.2-PM	$ 14,217.40	$ 139,145.02	$ 551,030.10	$ 340,718.23	$ 67,287.74	**$ 1,112,398.56**
Labour.3-Engineering	$ -	$ 304,176.60	$ 2,519,127.00	$ 755,262.20	$ 196,462.62	**$ 3,775,028.40**
Labour.4-Communications	$ 9,360.00	$ 213,408.00	$ 245,232.00	$ 281,357.61	$ 135,162.37	**$ 884,520.00**
Labour.5-Marketing	$ -	$ 114,147.09	$ 65,968.59	$ 48,267.87	$ -	**$ 228,384.00**
Material	$ -	$ 160,770.09	$ 1,538,698.44	$ 2,474,119.25	$ 76,412.21	**$ 4,250,000.00**
Material.4-Non Stock PO Outstanding	$ -	$ 160,770.09	$ 1,538,698.44	$ 2,474,119.25	$ 76,412.21	**$ 4,250,000.00**
Outside Services	$ -	$ 1,137,375.46	$ 2,031,706.98	$ 916,072.85	$ 235,713.48	**$ 4,320,868.67**
Outside Services.1-General	$ -	$ 418,034.54	$ 626,535.85	$ 665,929.64	$ 160,368.65	**$ 1,870,868.67**
Outside Services.2-PO Outstanding	$ -	$ 719,340.92	$ 1,405,171.13	$ 250,143.21	$ 75,344.83	**$ 2,450,000.00**
Total:	**$ 23,577.40**	**$ 2,135,946.26**	**$ 6,951,763.11**	**$ 4,815,798.01**	**$ 711,038.42**	**$ 14,638,123.63**

5. GOVERNANCE

PROJECT FUNCTIONAL STRUCTURE

Refer to *ODERA - Org Chart* in Appendix I for project organization.

PROJECT ROLES & RESPONSIBILITIES

ROLE		RESPONSIBILITY
EXECUTIVE SPONSOR - Provides overall strategic direction and high-level support for the project	Guillaume Paradis Laurie Heuff Mark Fernandes	- Secure necessary resources and funding - Remove roadblocks and escalate critical issues to the highest level - Ensure alignment with overall business strategy and grid modernization objectives and timelines - Approve major project milestones and deliverables - Provide final project approval - Provide support from a rate application and budget perspective, ensuring the project objectives and outcomes are clearly defined and defensible with the regulator within the 2026-2030 Rate Application
STEERING COMMITTEE - Provides strategic oversight, guidance, and decision-making for the project	Steve Hawthorne Jenna Gilllis Sarah Green Shawn Carr	- Review and approve project plans, budgets, and schedules - Monitor high-level project progress and performance - Ensure alignment with organizational goals and priorities - Provide strategic guidance to the Project Manager - Authorize high-level changes and critical decisions - Resolve cross program issues and strategic issues with senior stakeholders - Provide support to the program and its management team - Approve financial & schedule progress at project gates
PROJECT MANAGER - Responsible for the overall planning, execution, and delivery of the project	Andrzej Tomalik	- Develop and manage the project plan, budget, and schedule - Coordinate and manage project resources - Monitor project progress and manage project risks and issues - Manage project scope and changes - Ensure project quality and compliance - Define the project roadmap and alignment with project objectives - Manage relationships with key stakeholders and communicate program progress and risks to executive leadership (steering committee) and funding authorities (NRCan) - Provide guidance and direction to the Design, Customer Experience and Regulatory Affairs teams; act as escalation point for program-level issues - Responsible for coordinating external contracts and financial approvals - Facilitate communication and collaboration between the Technical Authority and other project teams - Ensure that technical decisions are integrated into the overall project plan

ROLE		RESPONSIBILITY
DESIGN LEAD - Leads the design and development of the product's functional and technical aspects	Andrew Fawcett	- Oversee the work of the Functional Team Lead, Technical Team Lead, and IT Project Manager. - Ensure consistency and integration of design elements - Manage design reviews and approvals - Ensure the design meets functional and technical requirements - Lead system design - Identify and manage design risks and issues, and support management of overall project risks and issues - Work with the technical authority to ensure designs are viable - Coordinate creation and verification of system-level requirements - Responsible for review & approval of subsystem-level requirements - Responsible for system design documentation - Responsible for functional & technical success of system - Support Project Manager as required - Manage design reviews and approvals, including those involving the Technical Authority.
REGULATORY AFFAIRS LEAD - Ensures the product complies with all relevant regulations and standards	April Barrie	- Act as primary point of contact to OEB - Identify and interpret applicable regulations - Develop and implement regulatory compliance plans - Prepare and submit regulatory filings. - Ensure that the product meets all regulatory requirements
CUSTOMER EXPERIENCE LEAD - Ensures the product delivers a positive and user-friendly experience	Shane Labrash	- Responsible for the design and delivery of the customer facing aspects of the project - Conduct user research and gather customer feedback - Define user requirements and specifications - Coordinate development of user interface and user experience design - Conduct usability testing and analysis - Ensure that the product meets customer expectations and needs - Develop marketing and knowledge dissemination materials and coordinate knowledge dissemination events - Coordinate work with customer, marketing and communications resources for the project
FUNCTIONAL TEAM LEAD - Leads the team responsible for defining and implementing the product's functional requirements	Zach Bacon Zach Leger Stephanie Pichette David Gill	- Support Design Lead in creation of system-level requirements - Work closely with Technical Team Leads to create sub-system requirements - Responsible for functional interfaces between assigned function and the rest of the system - Identify and support management of design risks and issues - Responsible for verification of sub-system requirements - Oversees functional testing and validation - Support system design - Support Project Manager & Design Lead as required - Responsible for functional success of the assigned function(s)

ROLE		RESPONSIBILITY
TECHNICAL TEAM LEAD - Leads the team responsible for the technical design, development, and implementation of the product	Maiss Al-Obaidi	- Develop technical specifications and Support Design Lead in creation of system-level requirements - Work closely with Functional Team Leads to create sub-system requirements - Responsible for technical solution compliance to system and sub-system level requirements - Work closely with the IT PM to coordinate technical work to achieve functional requirements - Responsible for sub-system technical design documentation - Support system design - Conduct technical reviews and testing - Identify and support management of design risks and issues - Responsible for external technical coordination with vendors and contractors - Support Project Manager & Design Lead as required - Responsible for technical success of the assigned function(s)
IT PROJECT MANAGER - Leads the team responsible for the IT infrastructure and support required for the product	Jennie Panesar	- Collaborate closely with IT SMEs and the Design Lead to coordinate technical work, ensuring alignment with project needs and objectives to meet functional requirements - Lead the IT project team, ensuring comprehensive IT support and active participation - Coordinate IT resource planning with the Design Lead and Project Manager - Facilitate communication between the Design Lead and IT SMEs - Serve as the primary point of contact for project communications, keeping the IT team informed - Act as the escalation point for IT-related issues - Generate and distribute project status reports and dashboards as required by the IT Division - Identify and support management of IT design risks and issues
TECHNICAL / APPROVAL AUTHORITY - Provides the final technical approval, and ensures architectural integrity	Kristopher Lelliott Ronnie Potvin Santhosh Jayasankar Shervin Sheidaei Mustafa Kapadia April Barrie Shawn Carr	- Review and approve all major technical designs and implementations - Review and approve system-level requirements - Provide guidance & expertise to technical leads and their teams - Approve technical aspects of design gates - Maintain clear approval scopes and processes - Provide final technical sign-off
IT SMEs	Abdelrahman Eldosouky Ismail Afia Shervin Sheidaei Santhosh Jayasankar Elvis ERharuyi Shannon Fowler Samuel Nazair	- Support technical Team lead and technical design as required - Support Project Manager & Design Lead as required - Executes specific tasks or deliverables per expertise - Contribute specialized knowledge (e.g., development, testing, design). - Collaborates with other team members to achieve project goals. - Report on progress

ROLE		RESPONSIBILITY
OPERATIONS SMEs	Megan Lawton Greg McAuley Raed Abdullah Sarfraz Mansuri Kristopher Lelliott Jake Martin	- Support Design Lead in creation of System Level requirements - Support Project Manager & Design Lead as required - Support sub-system and system testing

REVIEWS AND SIGNATURES

Gate reviews will be conducted at the completion of each of the project phases with reviews by the Technical Authority and Steering Committee, and shall follow the Project Gate Checklist:

Table 7: Project Gates

Key Gate Review Points	Date
Project Initiation Gate	Apr 28, 2025
Preliminary Design Gate	Jan 8, 2026
Detailed Design Gate	Nov 9, 2026
Design Verification & Test Gate	Mar 3, 2027
Technology Pilot Deployment Gate	Apr 3, 2028
Project Close Out Gate	June 12, 2028

CHANGE MANAGEMENT PROCESS

Changes will be managed through Hydro Ottawa existing project management methodologies. The overall project will be evaluated at each gate milestone against the project goals and objectives identified in the project charter. Financial changes will be managed through C55 change request process, and technical changes will be managed through technical signing authority review where applicable.

6. RISKS

KEY PROJECT RISKS

Project risk register (*ODERA – Risk Register*) shall be maintained and updated throughout the project life cycle. Key risks areas that shall be monitored and mitigated include:

- **HOL Funding Risk:** The HOL's portion of the project funding is contingent on successful approval of the 2026 Rate Application. Failure to secure the funding for this project through the rate application will significantly impact the project progression.
- **Technology Risk:** The project relies on emerging technologies (AI/machine learning, DER integration); consequently, there is a risk that the technology may not perform as expected or that unforeseen technical challenges may arise. The project's success hinges on the ability to advance the Technology Readiness Level (TRL) of the DER aggregator and load forecaster & DR trigger platforms. Failure to achieve the planned TRL will impact project outcomes. Due to the funding submission deadline a thorough solution design and market analysis could not be completed, continued due diligence is required.
- **Customer Adoption Risk:** The success of the project depends on customer willingness to enroll and actively participate in the program. Low customer adoption will limit the project's impact, affect statistically significant load curtailment potential, and limit lessons learned for full future deployment. The project shall develop a strategy that focuses on education, convenience, and value by focusing on clear communication, a simplified program process, compelling incentives, and addressing privacy and data concerns.
- **Integration Risk:** Integrating the solution with Hydro Ottawa's existing systems (Enterprise Service Bus, AMI) may present challenges and could lead to delays or increased costs. Dependencies specifically pertaining to ADMS and AMI 2.0 shall be addressed and confirmed early in the preliminary design phase. Alternate strategies shall be developed for cases where those dependencies cannot be maintained, as may be the case with the ADMS project, which is in the planning stages as of this writing.
- **Regulatory and Compliance Risk:** Changes in regulations or policies related to DERs, data privacy, or energy management could affect the project's scope or feasibility.
- **Timeline Risk:** The project timeline is subject to change, and unforeseen delays could occur due to technical issues, regulatory changes, or resource availability. Additionally, the project timeline has very little float.
- **Data Privacy Risk:** The project must manage data privacy risks associated with collecting and using customer DER data.
- **Resource Availability Risk:** The project is constrained by the availability of resources from Hydro Ottawa and project partners. This project has a high resource requirement and availability may present challenges for project completion, factors such as competing projects, insufficient head count and lack of the right resources may impact project timelines.
- **AMI 2.0 Deployment Risk:** The project's benefits could be enhanced by the timely deployment of AMI 2.0 meters, which is subject to regulatory approval. Delays in AMI 2.0 deployment could limit the project's potential.
- **Procurement Risk:** There is a risk that Hydro Ottawa will be unable to procure required vendors within the project timeline.

- **IESO Collaboration Risk:** The project could benefit from collaboration with the IESO and the use of their Peak Perks platform. However, there is a risk that this collaboration will not be successful or that the IESO's platform will not be compatible with Hydro Ottawa's needs due to potential competition with IESO's Peak Perks Program for same customers / DERs. This competition risks the success of the program due to a lack of customer participation or customer participation conflicts.
- **Funding Risk:** While Hydro Ottawa and project partners have committed funding to the project, there is a risk that additional funding sources will not be available or that the project will experience cost overruns. Budget refinement is on-going, including treatment of costs (Opex vs Capex, variance account).
- **Cybersecurity Risk:** The project must ensure that the technology and data are secure from cyber threats. IT investments will reduce partner dependency on the distribution grid model, thus mitigate risk of privacy breaches, unauthorized knowledge of potential grid vulnerabilities, variation in platform providers' approach to assessing target groups, and improve cross-partner data transaction & computation overhead costs.
- **Public Acceptance Risk:** There is a risk that the public will not be accepting of the project or that there will be concerns about the use of customer DER data and utility control of customer DERs. This could result in the project not being able to achieve required customer participation.

INTERRELATED PROJECTS

ADMS: Progression of the ADMS project shall be closely coordinated with the ODERA project since the ADMS platform promises an enhanced integration solution for the pilot and will ultimately become a part of the complete ODERA solution. ODERA project scope and timeline of activities shall be coordinated with the ADMS project plan once it becomes available. In the event that the ADMS interdependencies cannot be aligned with the timeline and objectives of the project, workaround solutions for addressing the functionalities promised by ADMS shall be developed, and a solution assessment shall be completed in the preliminary design phase.

EV Everywhere: Hydro Ottawa has been a partner to the EV Everywhere trial project led by vendor and funded in part by the IESO. This project started in April 2022 and is ongoing until winter 2026. The following outcomes are expected:

- Granular demand response events (branded "Grid Smart" events) which use electric vehicles, telematics, and internet connected EVSEs to forecast overloads on two static circuits in the Hydro Ottawa service area.
    - Early BETA results with a small cohort of test users are promising and show value of DR at a more granular level.
        - Hydro Ottawa will have recruited >100 trial participants for this program
- DR events will also discharge utility owned battery storage to strategically offset or support curtailment requirements.

A customer transition plan from EV Everywhere to ODERA may be required if both programs will be in the market at the same time and in the same area. The transition strategy shall be developed in this case in order to avoid the potential for competing programming.

Peak Perks: IESO, through Save on Energy brand, released an incentive program on Jan 7, 2025 for "small businesses with an eligible smart thermostat [and battery storage devices to] join more than 200,000 participants across Ontario being financially rewarded for taking control of their energy use and energy savings with Save on Energy's Peak Perks Program". This program is in direct competition with our project and next steps will require close coordination between IESO and Hydro Ottawa.

HydroOttawa

PROJECT CHARTER AUTHORIZATION

☐x Roles and Responsibilities attached

☐x Risk Plan attached

☐x Quality Plan attached

☐x Communication Plan attached

Project Steering Committee	Steve Hawthorne
Title	Director, Distribution Program Delivery
Date	2025-05-15
Signature	DocuSigned by: Steve Hawthorne 3FFDCAB677014DC...

Project Steering Committee	Sarah Green
Title	Director, IT Planning, Programs and Grid Technology
Date	2025-05-15
Signature	Signed by: Sarah Green FAADFFA1AC9F40F...

Project Steering Committee	Shawn Carr
Title	Director, Energy Transition Customer Strategy and Innovation
Date	2025-05-16
Signature	DocuSigned by: Shawn Carr DA06C4E23EA04F5...

Project Steering Committee	Jenna Gillis
Title	Director, Distribution Engineering and Asset Management
Date	2025-05-21
Signature	Signed by: Jenna Gillis B97D82B8FE0A48D...

Internal Stakeholder	Gaurav Kaushish
Title	Senior Engineer, Distribution
Date	2025-05-23
Signature	Signed by: gauravkaushish@hydroottawa.com 606D33DD11CB4E1...

Internal Stakeholder	Bob Harrington
Title	Senior Engineer, Technical Standards
Date	2025-05-30
Signature	Signed by: Bob Harrington AC89CF38D0F14F0...

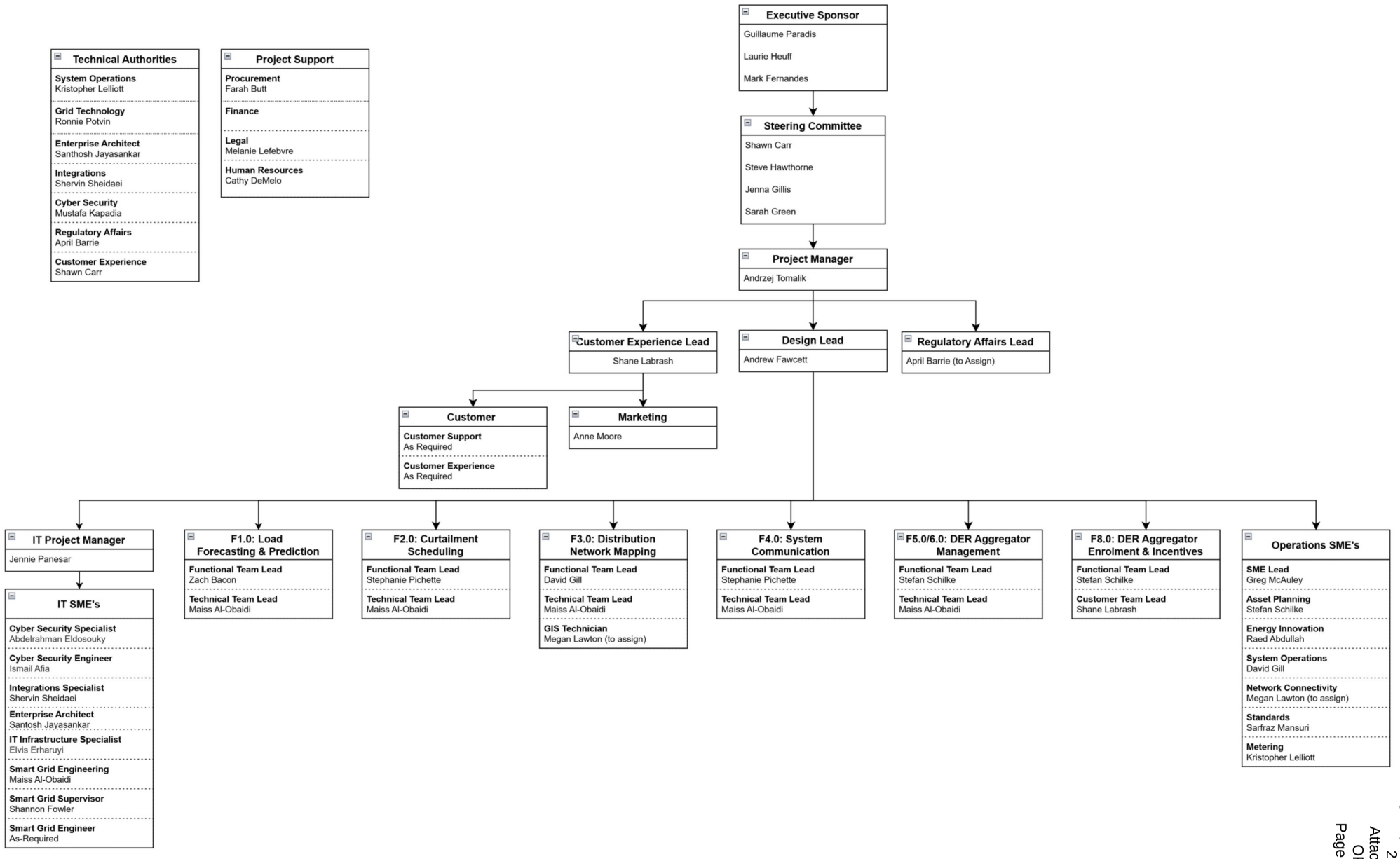
Project Manager Name	Andrzej Tomalik
Title	Senior Engineer, Distribution
Date	2025-06-03
Signature	Signed by: Andrzej Tomalik D70AF1F342324AE...

Organization Chart

Appendix I

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Ottawa Distributed Energy Resource Accelerator (ODERA) - Organizational Chart



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Project Quality Plan (PQP)

Appendix II

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Project Quality Plan

Project Name	Ottawa Distributed Energy Resources Accelerator (ODERA)		
Project No.	9202016181		
Author	Andrzej Tomalik	Date	January 2, 2025

For each category, define what will be required to manage quality on this project.

Regulations and Policies

- Compliance with industry standards and regulations:
  - OEB
  - IESO
  - Canadian Electrical Code
- Compliance with Hydro Ottawa design guides, equipment specifications, standards, policies and procedures.
- Audit and reviews of quality management requirements and policies

People

- Identify roles, responsibilities and accountabilities of the project team in the project charter and Roles and Responsibilities document.
- Maintain open communication with project stakeholders for updates, changes and issues.
- Create channels for team members and stakeholders to provide feedback on quality-related matters, ensuring continuous improvement.

Processes & Procedures

- ODERA Project Charter
- Project Execution Plan (ODERA Schedule)
- ODERA Project Gate Checklist
- ODERA Project Design Checklist

Resources (other than people)

- Employ Microsoft, Google and Hydro Ottawa tools to monitor project progress, quality, schedule and budget including, but not limited to:
  - MSOffice
  - MSProject
  - Google Docs
  - Hydro Ottawa Copperleaf, Hubble, Esker, JDE

Describe how each of the following aspects of quality management will be addressed

Quality Control

- Review all deliverables internally and approve per ODERA - Approval Work Flows. Solicit input from internal subject matter experts (SMEs) including, but not limited to:
  - Technical subject matter experts (SMEs) - IT, Grid Tech, Grid Modernization, Asset Planning, Metering.

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- Regulatory Affairs
- Standards specialist
- Customer Experience and Communications
- Operations, Maintenance and Reliability

- Maintain comments resolution logs for engineering design deliverables
- Develop schedule for conducting regular inspections of vendor supplied deliverables to ensure compliance with specifications and fit for purpose supply.
- Identify Hydro Ottawa procedures for identifying, documenting, and addressing non-conformances, including:
  - Identification of the non-conformance. ○ Immediate corrective actions taken.
  - Root cause analysis to prevent future occurrences.
- Maintain a Non-Conformance Register to track issues and resolutions.

Quality Assurance -

- Foster a culture of quality among all project stakeholders.
- Ensure stakeholder satisfaction through continuous engagement and feedback.
- Establish criteria for the selection of suppliers and subcontractors based on their ability to meet quality requirements.
- Implement a supplier evaluation process to assess performance regularly and ensure compliance.
- Review quality policies and quality control processes of suppliers.
- Employ competent vendors and contractors that follow industrial regulations, policies and best practices.
- Maintain clear and comprehensive project documentation.
- Develop and formalize new processes, procedures and templates.
- Continuously improve processes based on feedback and performance metrics.

Quality Improvement –

- Develop and maintain a Value Improvement Log.
- Implement Lessons Learned from past projects.
- Develop and maintain a Lessons Learned log.
- Analyze the root causes of raised quality issues and implement corrective actions.

Communication Plan

Appendix III

For Hydro Ottawa Use Only GDG0010 R-2 Schedule C1 ri

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Project Communications Plan

Project Name: Ottawa Distributed Energy Resources Accelerator (ODERA)

Project Number: 9202016181

Author: Andrzej Tomalik

Item #	Stakeholder	Message	Media	Sender	Frequency / Date	Comments
	***Who** is the intended receiver of the information?*	***What** is the message (e.g. status report, minutes, approved changes, contract)?*	***How** will the message be distributed (JDE project flag, e-mail, telephone, etc.)?*	***Who** will send the message?*	***When / how often** will the communications be distributed?*	*Has the communication been successfully received and understood?*
1	Steering Committee	High-level progress, key achievements, budget updates, risks	Meeting	Project Manager	Monthly	
2	Executive Sponsorship	High-level progress, key achievements, budget updates, risks	Project status report (PSR) meetings	Project Manager	Monthly	
3	Project Manager	Overall project status, risks, issues, resource allocation	meetings, project management tool updates,	Section Leads	Every two weeks	
4	Section Leads	Area-specific status, dependencies, resource needs, risks	team meetings, direct communication	Section Team, Functional / Team Leads	Every two weeks	
5	Functional / Team Leads	Task status, dependencies, functional coordination, risks	meetings, design documentation, direct comm.	Functional team	Weekly	
6	SMEs	coordination of technical information and problem-solving support	meetings, direct communication	Section Leads	As required	

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7	Technical Authority	Technical design, architecture, quality, risk assessment	Technical reviews, gate reviews, meetings	Project Manager	As required	

Clear, consistent, and transparent communication is essential for the success of this product development project. This communication plan is designed to keep all stakeholders informed, engaged, and aligned throughout the project's lifecycle. Regular evaluations will ensure that communication remains effective and responsive to the needs of the project.

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Approval Workflows

Appendix IV

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Requirements	Responsible	Approvers
Customer Level Requirements	Project Manager - Design Leads - Functional Team Leads - Technical Team Leads	Technical Authorities Steering Committee
System Level Requirements	Design Lead - Technical Team Leads - Functional Team Leads - SMEs (As Required)	Technical Authorities Project Manager IT PM Steering Committee
Sub-System Level Requirements	Functional Team Leads - Technical Team Leads - SMEs (As Required)	Technical Authorities Design Lead
Module Level Requirements	Functional Team Lead - Technical Team Lead - SMEs (As-Required)	Technical Authorities Design Lead
System Level Requirements Verification	Design Lead - Technical Team Lead - Functional Team Lead - SMEs (As-Required)	Technical Authorities Project Manager IT PM Steering Committee
Sub-System Level Requirements Verification	Functional Team Lead - Technical Team Lead - SMEs (As-Required)	Technical Authorities Design Lead
Module Level Requirements Verification	Functional Team Lead - Technical Team Lead - SMEs (As-Required)	Technical Authorities Design Lead

Design, Deployment & Test	Responsible	Approvers
Systems Architecture	Design Lead - Technical Team Leads - Functional Team Leads - SMEs (As Required)	Technical Authorities Project Manager IT PM
Sub-System Architecture	Functional Team Leads - Technical Team Leads - SMEs (As Required)	Technical Authorities Design Lead
Design Document	Design Lead - Technical Team Leads - Functional Team Leads - SMEs (As Required)	Technical Authorities Project Manager IT PM
Functional Flow Block Diagram Level 1	Design Lead - Technical Team Leads - Functional Team Leads - SMEs (As Required)	Technical Authorities Project Manager IT PM Steering Committee
Functional Flow Block Diagram Level 2 & below	Functional Team Leads - Technical Team Leads - SMEs (As Required)	Technical Authorities Design Lead
System Level Test Plans & Test Reports	Design Lead - Technical Team Leads - Functional Team Leads - SMEs (As Required)	Technical Authorities Project Manager IT PM
Sub-System Level & Below Test Plans & Test Reports	Functional Team Leads - Technical Team Leads - SMEs (As Required)	Technical Authorities Design Lead
Pilot Deployment Plan	Design Lead - Technical Team Leads - Functional Team Leads - SMEs (As Required)	Technical Authorities Project Manager
Grid Wide Deployment Plan	Design Lead - Technical Team Leads - Functional Team Leads - SMEs (As Required)	Technical Authorities Project Manager IT PM

- Project Initiation
- Preliminary Design
- Detailed Design & Development
- Design Verification & Test
- Pilot Deployment
- Project Close Out

Risk Register

Appendix V

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	Category	Risk Event	Priority	Response Strategy	Disposition
WBS Code of Account	*See RBS for detailed breakdown of risk categories*	*(Properly worded, thorough description of event)*	*Red=High Yellow=Medium Green=Low*	*Define actions to: Passively accept, Actively accept, Transfer, Mitigate, Avoid*	*Status of this risk*
Project Initiation	Schedule	Grant Funding Risk: The project's funding and timeline are contingent on receiving approval for the NRCAN grant. Failure to secure the grant will significantly impact the project.	Green	NRCAN grant funding has been approved on March 8, 2025.	Closed
Preliminary and Detail Design	Cost	Technology Risk: The project relies on emerging technologies (AI/machine learning, DER integration); consequently, there is a risk that the technology may not perform as expected or that unforeseen technical challenges may arise. The project's success hinges on the ability to advance the Technology Readiness Level (TRL) of the DER aggregator and load forecaster & DR trigger platforms. Failure to achieve the planned TRL will impact project outcomes.	Yellow	Project Objectives have been revised to allow for a broad range of solutions.	Monitoring
Technology Pilot Deployment	Quality	Customer Adoption Risk: The success of the project depends on customer willingness to enroll and actively participate in the program. Low customer adoption will limit the project's impact, affect statistically significant load curtailment potential, and limit lessons learned for full future deployment.	Yellow	Revised project objectives to specifically include a focus on customer engagement solutions development.	Monitoring
Detail Design	Cost	Integration Risk: Integrating the DERMS solution with Hydro Ottawa's existing systems (Enterprise Service Bus, AMI) may present challenges and could lead to delays or increased costs. There are significant project dependencies on ADMS and AMI 2.0, and we are expecting change fatigue for System Operators due to DERMS being introduced a year after ADMS.	Red	AMI 2.0 denendency - no current issued identified ADMS - In the plaining stages until May 2025. Planning disucssions are exploring the possibility of ADMS development in a way that would align with ODERA objectives - continue to push developing ADMS along side ODERA. If not possible, alternate option using CYME and suitable data analytics vendor will be required.	Monitoring

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Technology Pilot Deployment	Schedule	Regulatory and Compliance Risk: Changes in regulations or policies related to DERs, data privacy, or energy management could affect the project's scope or feasibility.	Green	Regulatory and compliance activities are scheduled early in the project.	Monitoring
	Schedule	Timeline Risk: The project timeline is subject to change, and unforeseen delays could occur due to technical issues, regulatory changes, or resource availability.	Green	Schedule to be managed according to HOL project management practices.	Monitoring
Technology Pilot Deployment	Quality	Data Privacy Risk: The project must manage data privacy risks associated with collecting and using customer DER data.	Green	Cybersecurity will be addressed by HOL IT group as part of project scope. Revised project objectives to specifically include a focus on customer engagement solutions development, which include proactively alleviating data privacy concerns.	Monitoring
Preliminary and Detail Design	Schedule	Resource Availability Risk: The project is constrained by the availability of resources from Hydro Ottawa and project partners. Incremental headcount vs what has currently been built into 2026-2030 budget will be required.	Yellow	Preliminary design schedule and resource requirements have been refined. Schedule has been advanced to meet the NRCAN milestone requirements increasing the required resource loading. Discussions for resource availability are ongoing and are being reviewed against other ongoing projects including ADMS.	Monitoring
Technology Pilot Deployment	Schedule	AMI 2.0 Deployment Risk: The project's benefits could be enhanced by the timely deployment of AMI 2.0 meters, which is subject to regulatory approval. Delays in AMI 2.0 deployment could limit the project's potential.	Green	Coordination activities with metering are ongoing. Deployment will be coordinated with the needs of the project.	Monitoring
Preliminary and Detail Design	Schedule	Procurement Risk: There is a risk that Hydro Ottawa will be unable to procure a suitable DER aggregator platform or that the selected platform will not be able to meet the project's requirements.	Green	Vendors have already been previously evaluated as the potential DER aggregators for the project. Vendor discussions shall be renewed in the Preliminary Design phase. Early vendor engagement activities, including contract negotiations, have been captured in the project schedule.	Monitoring

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Technology Pilot Deployment	Quality	IESO Collaboration Risk: The project could benefit from collaboration with the IESO and the use of their Peak Perks platform. However, there is a risk that this collaboration will not be successful or that the IESO's platform will not be compatible with Hydro Ottawa's needs due to potential Competition with IESO's Peak Perks Program for same customers / DERs.	Green	Engage early in program discussions with IESO to explore potential synergy with the existing Peak Perks program. If not successful, engagement of a new DER aggregator is already part of the project scope.	Monitoring
Technology Pilot Deployment	Cost	Funding Risk: While Hydro Ottawa and project partners have committed funding to the project, there is a risk that additional funding sources will not be available or that the project will experience cost overruns.	Green	Budget refinement is on-going, including treatment of costs (Opex vs Capex, variance account). Cost will be monitored per HOL project management practices.	
Technology Pilot Deployment	Quality	Cybersecurity Risk: The project must ensure that the technology and data are secure from cyber threats. Our IT investments will reduce partner dependency on the distribution grid model, thus mitigate risk of privacy breaches, unauthorized knowledge of potential grid vulnerabilities, variation in platform providers' approach to assessing target groups, and improve cross-partner data transaction & computation overhead costs.	Green	Cybersecurity will be addressed by HOL IT group as part of project scope	
Technology Pilot Deployment	Quality	Public Acceptance Risk: There is a risk that the public will not be accepting of the project or that there will be concerns about the use of customer DER data and utility control of customer DERs.	Green	Utility control of customer DERs is not a new concept with number of similar initiatives already deployed in the province and elsewhere.	
Preliminary Design	Schedule	Review and approval cycles with Technical Authorities and Steering Committee have been reduced in the schedule from 15 days to 10 days, posing a risk of schedule overrun.	Yellow	Schedule meetings early and manage stakeholder expectations for timely completion.	

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DEPARTMENT OF NATURAL RESOURCES

INNOVATION AND CLEAN GROWTH IN THE NATURAL RESOURCE SECTORS

ENERGY INNOVATION PROGRAM

NON-REPAYABLE CONTRIBUTION AGREEMENT

THIS AGREEMENT is made in duplicate

BETWEEN:

HIS MAJESTY THE KING IN RIGHT OF CANADA, represented by the Minister of Natural Resources ("Canada"),

AND:

HYDRO OTTAWA LIMITED, a corporation, incorporated under the laws of Ontario (the "Proponent").

WHEREAS Canada wishes to encourage the adoption of the **ENERGY INNOVATION PROGRAM** (the "Program");

WHEREAS the Proponent has submitted to the Minister a Proposal for the funding of a Project called **"THE OTTAWA DISTRIBUTED ENERGY RESOURCE (DER) ACCELERATOR PROJECT"** which qualifies for support under the Program;

WHEREAS Canada and the Proponent agree that in order for the Proponent to develop and implement the Project as described in Schedule A (Description of the Project), the Proponent will require financial assistance from Canada;

AND WHEREAS Canada is willing to provide financial assistance toward the Eligible Expenditures of the Project in the manner and upon the terms and conditions hereinafter set forth;

NOW, THEREFORE, Canada and the Proponent agree as follows:

1. INTERPRETATION

1.1 In this Agreement:

"Agreement" means this Agreement and the attached Schedules A and B;

"Claim Period" means the **quarter** to which each payment pertains;

"Completion Date" means the date that the Proponent shall complete the Project as specified in Paragraph 4.2;

"Contribution" means the funding provided by the Minister under this Agreement;

"Eligible Expenditures" means any expenditures Incurred by the Proponent, as set out in Schedule B (Budget and Eligible Expenditures), within the Eligible Expenditure Period in accordance with the terms and conditions of this Agreement; any Eligible Expenditures Incurred by the Proponent before this Agreement is signed by both Parties are limited to **Thirty percent (30 %)** of the Contribution;

"Eligible Expenditure Period" means the period starting **August 20, 2024** to **March 31, 2028**;

"Fiscal Year" means the period beginning on April 1st of any year and ending on March 31st in the next year;

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"Fixed Asset" means a tangible non-current asset, including buildings and equipment, acquired not for sale but for use for the Project during the Eligible Expenditure Period;

"Incurred" means, in relation to an Eligible Expenditure, an Eligible Expenditure that goods have been received by, and/or services have been rendered to, the Proponent;

"Incurred and Paid" means, in relation to an Eligible Expenditure, an Eligible Expenditure that the Proponent has paid for;

"Intellectual Property" means any intellectual property recognized by law, including any intellectual property right protected through legislation including governing patents, copyright, trade-marks, and industrial designs;

"Interest Rate" means the Bank Rate, as defined in the *Interest and Administrative Charges Regulations*, in effect on the due date, plus 300 basis points, compounded monthly. The Interest Rate for any given month can be found at: http://www.tpsgc-pwgsc.gc.ca/recgen/txt/taux-rates-eng.html;

"Minister" means the Minister of Natural Resources and includes any duly authorized officers or representatives;

"Party" means either the Proponent or Canada;

"Project" means the Project described in Schedule A (Description of the Project);

"Proposal" means a written Proposal signed by the Proponent on **May 3, 2024** including at least a background, purpose, work description, results expected, and a budget, which is accepted by the Minister for the Project;

"Total Government Funding" means cash contributions provided by the federal government and other contributions from the provincial/territorial and municipal governments toward the Total Project Costs; and,

"Total Project Costs" means the Contribution and other verifiable cash or in-kind contributions either received or contributed by the Proponent and directly attributable to the Project from **August 20, 2024** to the Completion Date.

1.2 The following schedules are attached to and made part of this Agreement:

a) Schedule A (Description of the Project); and

b) Schedule B (Budget and Eligible Expenditures).

1.3 In case of conflict between any provision in the main body of this Agreement and a provision in a schedule attached hereto, the provision in the main body of this Agreement shall take precedence.

1.4 Grammatical variations of the above defined terms have similar meanings. Words importing the singular number only shall include the plural and vice versa.

2. REPRESENTATIONS AND WARRANTIES

2.1 The Proponent represents and warrants that all factual matters contained in the Proposal and all supporting material submitted are true and accurate in all material respects, and that all estimates, forecasts and other related matters involving judgement were prepared in good faith and to the best of its ability, skill and judgement.

2.2 The Proponent represents and warrants that it is duly incorporated or registered and validly existing in good standing under the laws of Canada and has the power and authority to carry on its business, to hold property, and undertakes to take all necessary action to maintain itself in good standing and preserve its legal capacity during the term of this Agreement.

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2.3 The Proponent represents and warrants that the signatory to this Agreement has been duly authorized to execute and deliver this Agreement on its behalf.

2.4 The Proponent represents and warrants that the execution, delivery, and performance of this Agreement have been duly authorized and when executed and delivered will constitute a legal, valid, and binding obligation of the Proponent enforceable in accordance with its terms.

2.5 The Proponent represents and warrants that it has not, nor has any person offered or promised to any official or employee of His Majesty the King in Right of Canada, for or with a view to obtaining this Agreement any bribe, gift or other inducement and it has not nor has any person on its behalf employed any person to solicit this Agreement for a commission, fee or any other consideration dependent upon the execution of this Agreement.

3. DURATION OF THE AGREEMENT

3.1 This Agreement comes into force when signed by the Parties.

3.2 Except as otherwise provided in the articles below, this Agreement will expire on the latest of:

a) the Completion Date;

b) the completion of the Project to the satisfaction of the Minister; or

c) the date on which all amounts owed by the Proponent to the Minister under this Agreement have been paid in full.

3.3 The following clauses shall survive the expiration of this Agreement for an additional five (5) years :

a) Article 8 (Accounts and Audits);
b) Article 9 (Intellectual Property);
c) Article 10 (Indemnity);
d) Article 11 (Default);
e) Article 13 (Reports); and
f) Article 26 (Dispute Resolution).

4. CONDUCT OF PROJECT

4.1 The Proponent shall carry out the Project promptly, diligently and in a professional manner and in accordance with the terms and conditions of this Agreement.

4.2 The Proponent shall complete the Project by **March 31, 2028**, unless terminated earlier pursuant to the provisions of this Agreement.

4.3 The Proponent shall comply with all applicable federal, provincial and municipal laws in relation to the Project.

4.4 The Parties are satisfied that any legal duty to consult with Indigenous groups affected by the Project, and where appropriate, to accommodate Indigenous groups' concerns has been met and continues to be met. If as a result of changes to the nature or scope of the Project Canada determines that a legal duty to consult is triggered, the Proponent agrees that all of Canada's obligations pursuant to this Agreement will be suspended from the moment that Canada informs the Proponent that a legal duty to consult arises.

In the event that a legal duty to consult arises, the Proponent agrees that:

a) Canada will withhold any payment of the Contribution toward Eligible Expenditures until Canada is satisfied that any legal duty to consult with, and where appropriate, to accommodate Indigenous groups has been met and continues to be met;

b) if, as a result of such changes to the Project, Canada determines that further consultation is required, the Proponent will work with Canada to ensure that the legal duty to consult, and where appropriate, to accommodate Indigenous groups, is met and continues to be met to Canada's satisfaction; and

c) it will consult with Indigenous groups that might be affected by the changes to the Project, explain the Project to them, including Canada's role, and will provide a report to Canada, which will include:

i) a list of all Indigenous groups contacted;

ii) a summary of all communications to date with the Indigenous groups, indicating which groups support or object to the Project, and whether their positions are final, preliminary or conditional in nature;

iii) a summary of any issues or concerns that the Indigenous groups have raised and an indication of how the Proponent has addressed or proposes to address those issues or concerns; and

iv) any other information Canada may deem appropriate.

5. IMPACT ASSESSMENT

5.1 If, within the Eligible Expenditure Period, the Project becomes a "project" carried out on federal land or outside of Canada according to the *Impact Assessment Ac*t, the Parties agree that Canada's obligations under this Agreement will be suspended until:

a) a determination indicating that the carrying out of the Project is not likely to cause significant adverse environmental effects by the Minister or another authority referred in the *Impact Assessment Act*; or

b) if the carrying out of the Project is likely to cause significant adverse environmental effects, a decision of the Governor in Council indicates that those effects are justified in the circumstances.

5.2 It is understood that the Parties may examine the need to modify or terminate the Agreement if the Project allows the realization in whole or in part of a "project" within the meaning of the *Impact Assessment Act*.

5.3 It is understood, that, in the event that the Project becomes a "project" as defined in Paragraph 5.2 above, the Minister has no obligation to request a decision by the Governor in Council, and may, terminate this Agreement with immediate effect by giving notice in writing to the Proponent. Following such termination, no further Contribution will be disbursed under this Agreement, and the Minister will not be liable for any direct, indirect, consequential, exemplary, or punitive damages, regardless of the form of action, whether in contract, tort, or extra-contractual liability, or otherwise, arising from the termination.

6. CONTRIBUTIONS

6.1 Notwithstanding any other provision of this Agreement, the Contribution shall not in any circumstances exceed the lesser of:

a) **Forty Six percent (46%)** of Total Project Costs incurred; and
b) **Six Million Dollars ($6,000,000).**

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6.2 The Fiscal Year allocations for the Contribution are as follows:

2024-25 Zero Dollars ($0)
2025-26 Two Million Dollars ($2,000,000)
2026-27 Two Million Five Hundred Thousand Dollars ($2,500,000)
2027-28 One Million Five Hundred Thousand Dollars ($1,500,000)
Total: Six Million Dollars ($6,000,000)

Any reallocation of the Contribution amounts in whole or in part from one Fiscal Year to another shall require a written amendment signed by the Parties.

6.3 In order to be eligible to receive payment for any remaining portion of the Contribution as described herein, the Proponent must submit its final claim for payment on or before **May 31, 2028**.

6.4 The Minister will not contribute to any Eligible Expenditure Incurred by the Proponent prior to or after the Eligible Expenditure Period.

6.5 If by the Completion Date, the Total Government Funding as set out in Schedule B (Budget and Eligible Expenditures) that the Proponent has received exceeds **One Hundred percent (100%)** of the Total Project Costs incurred, the Minister may require the Proponent to reimburse such excess back to Canada.

6.6 The Proponent represents that no other federal, provincial, territorial or municipal government assistance, other than those described below and listed in Schedule B (Budget and Eligible Expenditures), has been or will be provided in respect of the Total Project Costs incurred:

Canada: Six Million Dollars ($6,000,000)
Other Federal: Zero Dollars ($0)
Provincial: Zero Dollars ($0)
Territorial: Zero Dollars ($0)
Municipal: Zero Dollars ($0)
Total Government Funding: Six Million Dollars ($6,000,000)

The Proponent shall advise the Minister promptly of any change in the Total Government Funding listed above during the term of this Agreement.

6.7 Canada shall not be liable to pay any Contribution after **December 31, 2025**, until the Proponent provides Canada with confirmation of its rate application approval in accordance with any relevant decision from the provincial electricity regulator as outlined in Schedule A (Description of the Project) task #1 of this Agreement. Such confirmation from the Proponent must be satisfactory to the Minister and its acceptance is subject to the Minister's sole discretion. In the event that the Proponent fails to provide to the Minister the required confirmation for the execution of Schedule A (Description of the Project), task #1, the Minister may terminate this Agreement forthwith upon written notice to the Proponent without any liability to either Party.

7. METHOD OF PAYMENT

7.1 Subject to the terms and conditions of this Agreement, following receipt of a claim for payment, acceptable to the Minister, for payment of Eligible Expenditures Incurred by the Proponent, Canada shall pay the Contribution towards the Eligible Expenditures of the Project.

7.2 In order to receive payment of Eligible Expenditures, the Proponent shall submit claims for payment accompanied by a financial report signed by the Chief Financial Officer or Duly Authorized Officer which, outlines Eligible Expenditures Incurred by category of cost, and progress reports as required in Article 13 (Reports). All claims must be submitted no later than sixty (60) days after the end of each Claim Period, except the claim for the final payment.

7.3 Canada may, at its sole discretion and based on Canada's assessment of the risk associated to the Project, withhold a portion of the amount of the Contribution claimed during any given Claim Period. Canada may adjust the holdback during the term of this Agreement but

at no time shall the holdback exceed **Ten percent (10%)** of the Contribution. Canada shall release the holdback only after the Proponent has submitted and the Minister has accepted, to his satisfaction, all reports required under Article 13 (Reports).

7.4 Subject to the terms and conditions of this Agreement, if the Proponent cannot submit a claim for payment on or before March 31 of a Fiscal Year, the Proponent shall no later than April 5 provide the Minister with a signed statement of anticipated Eligible Expenditures Incurred up to March 31, in order for the Minister to establish a Payable at Year-End.

7.5 Notwithstanding Paragraphs 7.1 to 7.2 above, starting on **December 31, 2025**, Canada shall withhold **One Hundred percent (100%)** of any payment after task #1 outlined in Schedule A (Description of the Project) of this Agreement until the Proponent has met the conditions outlined in Paragraph 6.7 of this Agreement.

7.6 Notwithstanding Article 25 (Amendments), following receipt of a written request from the Proponent in accordance with Article 24 (Notices), the Minister may approve in writing at his sole discretion an extension to submit any claim or any report required to be submitted in accordance with this Agreement.

7.7 Where for any reason Canada determines that the amount of the Contribution disbursed exceeds the amount to which the Proponent is entitled or the Proponent is not entitled to the Contribution, the Proponent must repay to Canada no later than thirty (30) days from the date of the Minister's notice, the amount of the overpayment or the amount of the Contribution disbursed. If the amount is not repaid by its due date, interest accrues at the Interest Rate for the period beginning on the due date and ending on the day before the day on which repayment to Canada is received. Any such amount is a debt due to His Majesty the King in Right of Canada and is recoverable as such.

7.8 Without limiting the scope of the set-off rights provided for under the *Financial Administration Act*, it is understood that the Minister may set off against any amount that may be payable to the Proponent pursuant to this Agreement, any amounts owed and past due by the Proponent to His Majesty the King in Right of Canada under any legislation or contribution agreements and the Proponent shall declare to the Minister all amounts outstanding in that respect when making any claim under this Agreement.

8. ACCOUNTS AND AUDITS

8.1 Prior to the Completion Date and for five (5) years after the expiration of this Agreement, as described in Article 3 (Duration of the Agreement), the Proponent shall, at its own expense:

a) keep proper and accurate books, accounts, and records of its revenue received and expenses Incurred and Paid in connection with the Project and shall keep its invoices, receipts, and vouchers relating thereto;

b) keep proper and accurate records of all data, analyses, and other scientific or technical assessments and reports, and any and all information relating to the outputs and outcomes of the Project;

c) on demand, make available to the Minister such books, accounts, records, invoices, receipts, and vouchers referred to above and permit the Minister to examine and audit and take copies and extracts from such documents;

d) allow the Minister, at the Minister's own expense and discretion, to conduct a technical audit to verify that the proposed measures outlined in Schedule A (Description of the Project) were implemented in accordance with this Agreement; and,

e) allow the Minister, at the Minister's own expense and discretion, to conduct an audit to verify the accuracy of reports submitted under Article 13 (Reports).

8.2 In respect of Eligible Expenditures related to professional, scientific and contracting services outlined in Schedule B (Budget and Eligible Expenditures), Canada's auditors may,

acting reasonably, request that the Proponent's books, accounts and records be supplemented by information from the books, accounts and records of the subcontractors engaged by the Proponent having contracts in excess of **Twenty percent (20%)** of the Contribution for the purposes of the Project. The Proponent will use commercially reasonable efforts to obtain such information as is reasonably requested by Canada's auditors from the Proponent's subcontractors, subject to and to the extent permitted by terms of the applicable contracts and, in particular, the audit provisions of such contracts.

9. INTELLECTUAL PROPERTY

9.1 All Intellectual Property that arises in the course of the Project shall vest in the Proponent, or be licensed to the Proponent in the event that a Proponent's subcontractor retains title to such Intellectual Property.

9.2 The Proponent shall supply to Canada the reports and documents described in Article 13 (Reports), and the Proponent hereby grants to Canada a non-exclusive, irrevocable, world-wide, free and royalty-free license in perpetuity to use, modify, and, subject to the *Access to Information Act*, make publicly available such reports and documents for non-commercial governmental purposes.

10. INDEMNITY

10.1 Neither Canada, nor its employees, officers and agents, will have any liability in respect of claims of any nature, including claims for injury or damages, made by any person involved in the activities of the Project or as a result of or arising out of this Agreement, and the Proponent will indemnify and save harmless Canada, its employees, officers and agents, in respect of such claims.

11. DEFAULT

11.1 The Minister may declare that an event of default has occurred if:

a) the Proponent becomes insolvent or is adjudged or declared bankrupt or if it goes into receivership or takes the benefit of any statute from time to time in force relating to bankrupt or insolvent debtors;

b) an order is made which is not being contested or appealed by the Proponent or a resolution is passed for the winding up of the Proponent or it is dissolved;

c) in the opinion of the Minister, there has been a misrepresentation or breach of warranty under Article 2 (Representations and Warranties);

d) in the opinion of the Minister, acting reasonably, a material adverse change in risk affecting the fulfilment of the terms and conditions of this Agreement has occurred;

e) any term, condition or undertaking in this Agreement is not complied with, including, without limitation, any of those in Article 4 (Conduct of Project), Article 5 (Impact Assessment) or Article 7 (Method of Payment) and any such defect has not been cured by or remedied by the Proponent within thirty (30) days of written notice of such defect having been provided to the Proponent; or

f) the Proponent neglects or fails to pay the Minister any amount due in accordance with this Agreement.

11.2 If the Minister declares that an event of default has occurred, in addition to all other remedies provided under contract law, the Minister may exercise one or more of the following remedies:

a) suspend any obligation of Canada to contribute or continue to contribute to the Eligible Expenditures of the Project or a part of the Project, including any obligation to pay any amount owing prior to the date of such suspension;

b) terminate any obligation of Canada to contribute or continue to contribute to the Eligible Expenditures, including any obligation to pay any amount owing prior to the date of such termination;

c) terminate this Agreement; and

d) direct the Proponent to repay all or part of the Contribution which has been paid to the Proponent, together with interest from the date of demand at the Interest Rate, with the exception of an event of default listed in Paragraph 11.1(d). Any such amount is a debt due to His Majesty in Right of Canada and is recoverable as such.

For greater clarity, all above remedies are cumulative.

11.3 The fact that the Minister does not exercise a remedy that the Minister is entitled to exercise under this Agreement will not constitute a waiver of such right and any partial exercise of a right will not prevent the Minister in any way from later exercising any other right or remedy under this Agreement or other applicable law.

12. ACCESS

12.1 Prior to the Completion Date and for five (5) years after the expiration of this Agreement, the Proponent shall provide the Minister or Minister's representatives reasonable access to any premises where the Project takes place to assess the Project's progress or any element thereof, subject to providing reasonable notice and complying with the Proponent's safety requirements for such access.

13. REPORTS

13.1 The Proponent shall submit, no later than sixty (60) days after the Claim Period, the following documentation as per the template provided by Canada.

a) an updated Project quarterly cash flow statement and budget;

b) where applicable, a detailed breakdown of any capital equipment purchased, including make, model and unit price;

c) where applicable, an explanatory note signed by the Chief Financial Officer or duly authorized officer explaining what overhead expenditures were Incurred; and

d) a report of Project tasks to-date in sufficient detail, including outputs and key performance indicators, to allow progress to be evaluated.

13.2 The Proponent shall submit, no later than sixty (60) days after the Completion Date a final report, as per a template provided by Canada, which includes the following:

a) a financial report that shall demonstrate how the Contribution was used, including the receipt of goods and/or services being funded by Canada;

b) a final narrative report to describe how its activities have contributed to the achievement of the objectives of the Project as described in Schedule A (Description of the Project);

c) a certification that the claims for payment of Eligible Expenditures of the Project have been Incurred and Paid by the Proponent;

d) a public report that describes the Project and its results; and

e) a declaration as to the total amount of contributions or payments, including Total Government Funding, received by the Proponent.

13.3 For a period of five (5) years following the Completion Date, the Proponent shall submit, no later than sixty (60) days after each anniversary of the Completion Date, an annual outcome report, as per the template provided by Canada, which reports on the key performance indicators as described in Schedule A (Description of the Project).

14. DISPOSITION OF ASSETS

14.1 If, prior to the Completion Date and for three (3) years thereafter, the Proponent sells, leases or otherwise disposes of any Fixed Asset excluding Intellectual Property, where the cost of the Fixed Asset is part of the Eligible Expenditures under the Project to which Canada has contributed under this Agreement, and where the proceeds of the sale, lease or other disposition are not applied to acquire assets in replacement of the Fixed Asset, the Proponent shall immediately notify the Minister in writing of such sale, lease or disposition and, if the Minister so requires, the Proponent shall share with Canada the proceeds of the sale, lease or any other disposition in the same ratio as that of Canada's Contribution to the purchase of the Fixed Asset by the Proponent, except that Canada's share shall not exceed the Contribution.

15. SUBCONTRACTS

15.1 The Proponent shall not subcontract all or any part of the Project except as provided in the Proposal or as otherwise set forth below. The Proponent shall advise the Minister of any other new contract, not originally included in the Proposal, the Proponent enters into with a third party to undertake work on the Project where the estimate of the cost of the work to be performed exceeds **twenty percent (20%)** of the Contribution. The notice shall include a description of the extent and nature of the contracted work, the identity of the contractor, and the estimated cost of the contracted work. For greater certainty, for the purposes of this Article, there is no privity of contract between Canada and any of the Proponent's subcontractors; as such, the selection and amendment of any of the Proponent's subcontractors as may be listed in the Proposal is the sole responsibility of the Proponent and is not subject to the Minister's consent.

16. LEGAL RELATIONSHIP

16.1 Nothing contained in this Agreement shall create the relationship of principal and agent, employer and employee, partnership or joint venture between the Parties.

16.2 The Proponent shall not make any representation that:

a) the Proponent is an agent of Canada; or

b) could reasonably lead any member of the public to believe that the Proponent or its contractors are agents of Canada.

17. ACKNOWLEDGEMENT

17.1 The Proponent shall acknowledge the financial support of Canada in all public information produced as part of the Project.

17.2 The Proponent will seek prior written consent of the Minister for any public acknowledgement of the financial support of Canada to this Project through news releases, public displays, and public and media events.

17.3 Except for releases of information required to comply with securities regulations or other laws, where media announcements and public events relating to this Project are to be made by a Party, the Party shall use commercially reasonable efforts to give to the other a three (3) weeks

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prior written notice of any media announcement or public event and a reasonable opportunity to review and comment thereon.

17.4 The Proponent acknowledges that the Proponent's name, the amount awarded, and the general nature of the activities supported under this Agreement may be made publicly available by the Government of Canada.

18. TIME OF ESSENCE

18.1 Time is of the essence with respect to all provisions of this Agreement that specify a time for performance.

19. MEMBERS OF PARLIAMENT

19.1 No Member of the House of Commons or Senate shall be admitted to any share or part of this Agreement or to any benefit arising therefrom that is not otherwise available to the general public.

20. CONFLICT OF INTEREST

20.1 It is a term of this Agreement that all current or former public servants to whom the federal *Values and Ethics Code for the Public Sector*, federal *Policy on Conflict of Interest and Post-Employment*, or *NRCan Values and Ethics Code* applies shall comply with the Codes or Policy, as applicable.

20.2 If any individual working for the Proponent formerly provided consultancy services to the Minister that are related to this Agreement, particularly any services associated with developing the Agreement or developing the Project which is the subject of this Agreement, the Proponent is considered to be in a real, perceived, or potential conflict of interest situation.

20.3 If a conflict of interest situation arises during the Agreement, the Proponent shall notify the Minister, in the manner prescribed in Article 24 (Notices). Upon request, the Proponent shall notify the Minister of all reasonable steps taken to identify, avoid, prevent, and where it exists, resolve any conflict of interest situation.

20.4 The Minister may investigate a real, perceived, or potential conflict of interest and take such steps and measures as the Minister considers appropriate, including without limitation: informing the Proponent that it is in a conflict of interest situation; requesting specific actions be taken to correct the situation; requiring the Proponent to withdraw any individual from participation in the Project for reasons of conflict of interest; suspending payments under the Agreement; or terminating the Agreement.

21. FORCE MAJEURE

21.1 The Parties shall not be in default or in breach of this Agreement due to any delay or failure to meet any of their obligations caused by or arising from any event beyond their reasonable control and without their fault or negligence, including any act of God or other cause which delays or frustrates the performance of this Agreement (a “force majeure event”). If a force majeure event frustrates the performance of this Agreement, Canada will only be liable for its proportionate share of the Eligible Expenditures Incurred and Paid to the date of the occurrence of the event.

21.2 The performance of the obligation affected by a “force majeure event” as set out above shall be delayed by the length of time over which the event lasted. However, should the interruption continue for more than **thirty (30) days**, this Agreement may be terminated by Canada.

21.3 Should either Party claim the existence of a "force majeure event" as above, prompt notice thereof shall be given to the other Party and the Party claiming the existence of a "force majeure event" shall have the obligation to provide reasonable satisfactory evidence of the existence of such event and use its best efforts to mitigate any damages to the other Party.

22. GOVERNING LAW

22.1 This Agreement shall be interpreted in accordance with the applicable federal laws and the laws in force in Province of Ontario.

23. ASSIGNMENT

23.1 No benefit arising from this Agreement shall be assigned in whole or in part by the Proponent without the prior written consent of the Minister and any assignment made without that consent is void and of no effect.

24. NOTICES

24.1 The claims for payment, requests, reports, notices, repayments and information referred to in this Agreement shall be sent in writing or by any method of telecommunication and, unless notice to the contrary is given, shall be addressed to the Party concerned at the following address:

To Canada:

Jennifer Hiscock
Director of Electricity, Transportation & Buildings Innovation
Office of Energy Research and Development
Natural Resources Canada
580 Booth Street
Ottawa, Ontario
K1A 0E4
Telephone: (416) 276-2921
E-mail: energyinnovation-innovationenergetique@nrcan-rncan.gc.ca

To the Proponent:

Andrzej Tomalik
Senior Engineer, Distribution
2711 HUNT CLUB RD BOX 8700
Ottawa, Ontario
Canada
K1G 3S4
Telephone: 613-738-5499
E-mail: andrzejtomalik@hydroottawa.com

24.2 Requests, notices and documents are deemed to have been received, if sent by registered mail, when the postal receipt is acknowledged by the other Party; by facsimile or electronic mail, when transmitted and receipt is confirmed; and by messenger or specialized courier agency, when delivered.

24.3 The Minister and the Proponent agree to notify each other in writing if the above contact information changes. This requirement will not cause an amendment to the Agreement.

25. AMENDMENTS

25.1 No amendment of this Agreement or waiver of any of its terms and conditions shall be deemed valid unless effected by a written amendment signed by the Parties.

26. DISPUTE RESOLUTION

26.1 If a dispute arises concerning the application or interpretation of this Agreement, the Parties will attempt to resolve the matter through good faith negotiation, and may, if necessary and the Parties consent in writing, resolve the matter through mediation by a mutually acceptable mediator.

27. APPROPRIATION

27.1 The payment of monies by Canada under this Agreement is subject to there being an appropriation by Parliament for the Fiscal Year in which the payment of monies is to be made.

27.2 Notwithstanding any other provision of this Agreement, Canada may reduce or cancel the Contribution to the Project upon written notice to the Proponent in the event that the funding levels for the Department of Natural Resources are changed by Parliament during the term of this Agreement. In the event that Canada reduces or cancels the Contribution, the Parties agree to amend the Project and the Eligible Expenditures of the Project, namely this Agreement, to take into account the reduction or cancellation of the Contribution.

28. LOBBYING ACT

28.1 The Proponent shall ensure that any person lobbying on behalf of the Proponent is registered pursuant to the *Lobbying Act* and that the fees paid to the lobbyist are not to be related to the value of the Contribution.

29. SUCCESSORS AND ASSIGNS

29.1 This Agreement shall inure to the benefit of and be binding on the Parties and their respective representatives, successors and assigns.

30. OFFICIAL LANGUAGES/LANGUES OFFICIELLES

30.1 This Agreement is drafted in **English** at the request of the Parties. Les Parties ont convenu que le présent Accord soit rédigé en **anglais**.

30.2 All public information documents related to the Project prepared or paid for in whole or in part by Canada must be made available in both official languages, when the Department of Natural Resources judges that this is required under the *Official Languages Act*. Tout document d'information publique préparé ou payé en tout ou en partie par le Canada ayant trait au Projet doit être offert dans les deux langues officielles, lorsque le Ministère des ressources naturelles le juge pertinent, conformément à la *Loi sur les langues officielles*.

31. COUNTERPART SIGNATURE

31.1 This Agreement (and any amendments) may be signed in counterparts including facsimile, PDF and other electronic copies, each of which when taken together, will constitute one instrument.

32. SEVERABILITY

32.1 Any provision of this Agreement prohibited by law or otherwise ineffective, will be ineffective only to the extent of such prohibition or ineffectiveness and will be severable without invalidating or otherwise affecting the remaining provisions of the Agreement. The Parties agree to negotiate in good faith a substitute provision which most nearly reflects the Parties' intent in entering into this Agreement.

33. ENTIRE AGREEMENT

33.1 This Agreement constitutes the entire Agreement between the Parties with respect to the subject matter of this Agreement and supersedes all previous negotiations, communications, and other agreements, whether written or verbal between the Parties.

IN WITNESS THEREOF, this Agreement is duly executed on behalf of His Majesty the King in Right of Canada by an officer duly authorized by the Minister of Natural Resources and on behalf of the Proponent, by an officer duly authorized on its behalf.

HIS MAJESTY THE KING IN RIGHT OF CANADA

Leyburne, Drew 2025.03.08 14:04:47 -05'00'

Date

Drew Leyburne
Assistant Deputy Minister
Energy Efficiency and Technology Sector

HYDRO OTTAWA LIMITED

2025-03-07

DocuSigned by:
Bryce Conrad
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Date

Bryce Conrad
President and Chief Executive Officer

SCHEDULE A

To the Agreement between

HIS MAJESTY THE KING IN RIGHT OF CANADA

And

HYDRO OTTAWA LIMITED

DESCRIPTION OF THE PROJECT

PROJECT TITLE	**THE OTTAWA DISTRIBUTED ENERGY RESOURCE (DER) ACCELERATOR PROJECT**
PROJECT OBJECTIVE	The objective of this Project is to leverage AI-enhanced load forecast analytics at a granular, distribution transformer and feeder level, to strategically dispatch demand response signals for managing a variety of customer-owned DERs as a non-wires solution.
PROJECT SUMMARY	Under this Project, the Proponent will leverage demand response (DR) to incentivize customers to enroll their DERs in a targeted, resource- and asset-constrained community, Kanata North, with lower-than-average system reliability. The Proponent will develop and the design for the solution, including the high-level functional and architectural design, system and sub-system requirements, configuration of the DER aggregator, and the load forecasting and curtailment scheduling concept. The Proponent will demonstrate the system in an operational environment. The Proponent will a business analysis to assess the benefits of this approach in terms of reliability, affordability, and fit relative to traditional grid upgrades, including the use of the provincial Regulator's benefit-cost analysis framework.

BENEFITS	Benefits to Canadians:
	• Accelerate grid modernization to:
	  o Better optimize electricity system assets
	  o Increase reliability, resiliency, and flexibility
	  o Increase penetration of DER
	• Sets a technical and financial precedent for other electric utilities in developing their business beyond poles and wires
	• Demonstrates the possible role that an active electricity distribution system will have in a modern electric power grid.
	• Lays the groundwork for a more reliable and resilient electricity system
	• Explores alternative approaches to meeting grid needs at lowest cost
	• Share knowledge and insights to enhance public awareness
	
	Benefits to Stakeholders:
	• Explore the techno-economic potential of non-wires solutions to meeting grid needs in the goal of exerting downward pressure on electricity rates
	• Provides data and experience on customer behaviour. This is significant for the Canadian electricity sector as electric load continues to grow
	• Improve customer access to grid-integrated solutions
	• Explore new business models for electricity system stakeholders
	• Helps to enable customers to reduce their electricity bills.

PROJECT TASKS

#	Name	Description	Outputs
1	**Preparation**	Under this task, the Proponent will:	- Sub-systems and equipment procured

	December 31, 2025	- Procure the required sub-systems and equipment - Create the preliminary design for the solution - Complete the regulatory approval process with the provincial electricity regulator for their five-year rate and investment cycle.	- Preliminary system-level design document - Regulatory approval for investments
2	**Detailed design and development** **October 19, 2026**	Under this task, the Proponent will: - Validate the network model, and finalize design for IT/OT communications and sub-system configuration for load forecasting and curtailment scheduling - Prepare plans for testing - Prepare plans for pilot deployment	- Detailed design document of the solution - Test plans - Preliminary technology pilot deployment plan
3	**Testing, and AMI 2.0 deployment** **February 10, 2027**	Under this task, the Proponent will: - Verify the solution meets design requirements through testing and other verification methods - Prepare training materials - Update the pilot deployment plan based on learnings - Install AMI 2.0 meters	- Test documents - Training materials - Final technology pilot deployment plan - Installed AMI meters
4	**Technology pilot deployment** **March 31, 2028**	Under this task, the Proponent will assess the system in an operational environment.	- Operational forecasting and curtailment technology

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PERFORMANCE INFORMATION

Key Performance Indicators
1. Operational performance and business impact measures
2. Customer performance and impact measures
3. Knowledge dissemination measures
4. Longitudinal outcomes measures

SCHEDULE B

To the Agreement between

HIS MAJESTY THE KING IN RIGHT OF CANADA

And

HYDRO OTTAWA LIMITED

BUDGET AND ELIGIBLE EXPENDITURES

1. Subject to the limitations set out in Article 6 (Contributions), Eligible Expenditures shall be associated with the execution of the various activities as described in Schedule A (Description of the Project).

Approved Budget ($)	2024-25	2025-26	2026-27	2027-28	TOTAL ($)
Canada (NRCan)	**$ 0**	**$ 2,000,000**	**$ 2,500,000**	**$ 1,500,000**	**$ 6,000,000**
ELIGIBLE EXPENDITURES					
Salaries and Benefits	**$ 86,683**	**$ 950,021**	**$ 3,200,063**	**$ 920,400**	**$ 5,157,167**
Overhead	**$ 15,297**	**$ 167,651**	**$ 564,717**	**$ 162,424**	**$ 910,089**
Professional, Scientific and Contracting Services	[redacted]				**$ 2,450,000**
Travel, including Meals and Accommodations	**$ 1,522**	**$ 43,634**	**$ 33,509**	**$ 26,755**	**$ 105,420**
Equipment and Products	[redacted]				**$ 1,099,999**
Other expenses	**$ 0**	**$ 481,525**	**$ 631,515**	**$ 652,409**	**$ 1,765,449**
Total Eligible Expenditures	**$ 103,502**	**$ 2,875,186**	**$ 6,255,991**	**$ 2,253,445**	**$ 11,488,124**

INELIGIBLE COSTS					
INELIGIBLE EXPENDITURES					
Total Ineligible Expenditures	**$ 0**	**$ 0**	**$ 1,766,471**	**$ 1,383,529**	**$ 3,150,000**
IN-KIND COSTS					
Total In-Kind Costs	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**
				Total Ineligible Costs	**$ 3,150,000**

Total Project Costs	**$ 14,638,124**

Source of Contributions	Percent (%)	Cash ($)	In-Kind ($)	TOTAL ($)
Canada (NRCan)	**41 %**	$ 6,000,000	Not Applicable	**$ 6,000,000**
The Proponent	**59 %**	$ 8,638,124	$ 0	**$ 8,638,124**
TOTAL	**100%**	**$ 14,638,124**	**$ 0**	**$ 14,638,124**

NOTE: the following limitations apply to the approved budget above:

a) In accordance with the departmental GST/PST/HST certification form, the reimbursable Provincial Sales Tax, the Goods and Services Tax and Harmonized Sales Tax costs must be net of any tax rebate to which the Proponent is entitled.

b) In-kind costs are those contributions of goods or services provided by the Proponent or other contributors that are considered towards Total Project Costs; however; they are not Eligible Expenditures.

c) 'Salaries and benefits' costs are for employees on the payroll of the Proponent for the actual time spent by the employees on the Project.

d) Overhead expenditures directly related to the conduct of the Project, such as office operating expenses (e.g. telephone, internet, heat, electricity), are limited to **Fifteen percent (15%)** of total Eligible Expenditures.

e) Travel expenditures, including meals and accommodations, are to be based on National Joint Council Rates.

f) 'Capital expenditures for equipment and products' include the purchase, installation, testing and commissioning of qualifying equipment, material and products, as well as diagnostic and testing tools and instruments, and original equipment manufacturer warranty (including extended warranties where deemed appropriate to mitigate risk and lack of capacity).

2. Notwithstanding Article 25 (Amendments), provided the Contribution for any given Fiscal Year is not exceeded, the Proponent may adjust any cost allocated by Eligible Expenditure as listed above by up to **Twenty percent (20%)** of that cost without providing notice to Canada. At the time of submitting a claim for payment, the Proponent must provide Canada with a revised budget.

The Proponent may submit a written request to Canada to make an adjustment greater than **Twenty percent (20%).** The request must include a revised budget. This request is subject to the approval in writing by Canada's representative identified in Article 24 (Notices).

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-70

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / pp. 289-290 (pdf Exhibit 2 Part 3, pp. 289-290)

Preamble:
In its application, Hydro Ottawa identifies 4 distinct NWS initiatives/broader programs: NWCSP, BESS, EV Everywhere, and ODERA. Hydro Ottawa also mentions alternative energy models such as local flexibility markets, distributed system operator capabilities, and total grid orchestration capabilities.

QUESTION(S):

a) Please confirm if there are any other NWS initiatives, programs and/or projects beyond NWCSP, BESS, EV Everywhere, and ODERA for which Hydro Ottawa is requesting rate funding in this application. If there are any other proposed NWSs, please provide:
   i) The program name, activity description, funding being requested from rates (in total and annualized from 2026-2030), and total cost (including the amount and source of any external funding);
   ii) The corresponding system need, and the quantitative and qualitative benefits (including avoided/deferred costs) and costs associated with each NWS initiative and its corresponding traditional wires solutions, if any.

b) Please confirm the amount and where (e.g., under which program or investment category) the costs associated with local flexibility markets, distributed system operator capabilities, and total grid orchestration capabilities are being captured in this application, if applicable.

RESPONSE(S):

In its application, Hydro Ottawa identifies 2 distinct NWS programs: NWCSP and BESS. 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 and deploy NWS.

a) Hydro Ottawa would like to clarify that rate funding is not being requested for EV Everywhere, as noted in 2-Staff-68 part a).

At this time, there are no other proposed NWS programs or related projects, however as indicated in the DSO Capabilities Stakeholder Symposium on June 23-24, 2025, Hydro Ottawa is collaborating with other large distributors to investigate opportunities to develop shared capabilities and tools to administer a local flexibility market for NWS programs. If this collaboration comes to fruition, it would be funded through the Non-Wire Programming & System Integrations OM&A budget. As outlined on page 19 of Schedule 4-1-2 - Operations, Maintenance and Administration Program Costs, this budget program is intended to support the effective integration of third-party owned non-wires solutions. As the activities contemplated within this budget program are dependent on several external factors, including the pace of DER technology advancements, evolving policies and customer adoption rates, Hydro Ottawa is also proposing a Non-Wires Solutions Variance Account to record the difference between projected and actual NWS costs for NWS projects, offset by any external funding (see p.19 of Schedule 9-2-1 New Deferral and Variance Accounts and 1-Staff-18)

i) Not applicable

ii) Not applicable

b) Refer to response to part a). For clarity, Hydro Ottawa hasn't identified any specific investments categorized as distributed system operator capabilities and total grid orchestration capabilities.

Hydro Ottawa's current application focuses on grid modernization, which the company views as the essential groundwork for future DSO capabilities. While the application doesn't explicitly outline plans for specific DSO services, it details investments in foundational elements that are aligned with existing regulatory policies. These activities, as described in interrogatory response 2-PP-14, Table A, are intended to lay the groundwork for supporting DSO services in accordance with the forthcoming outcomes of the OEB's consultation process. Please see response to interrogatory 2-Staff-119 part a) for further information on Hydro Ottawa's Grid Modernization Strategy and Roadmap.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-71

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 300 (Exhibit 2 part 3, pdf p. 300)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 4 / Attachment F / pp. 40-11 (pdf Exhibit 2 part 3, pp. 533-534)

QUESTION(S):

a) Hydro Ottawa states it the system coincident peak occurs in the summer. Given the identification of non-emitting heat sources is a key element of Canada's 2030 Emissions Reduction Plan, does Hydro Ottawa expect to become a winter peaking system at some point in the future? Please discuss.

RESPONSE(S):

a) Yes, Hydro Ottawa expects to be a winter peaking utility by 2030 based on the Reference scenario of the Decarbonization Study. See section 9.4.2.1 of Schedule 2-5-4 - Asset Management Process for further detail.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-72

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 4 / p. 305 (pdf Exhibit 2 part 3, p. 305)

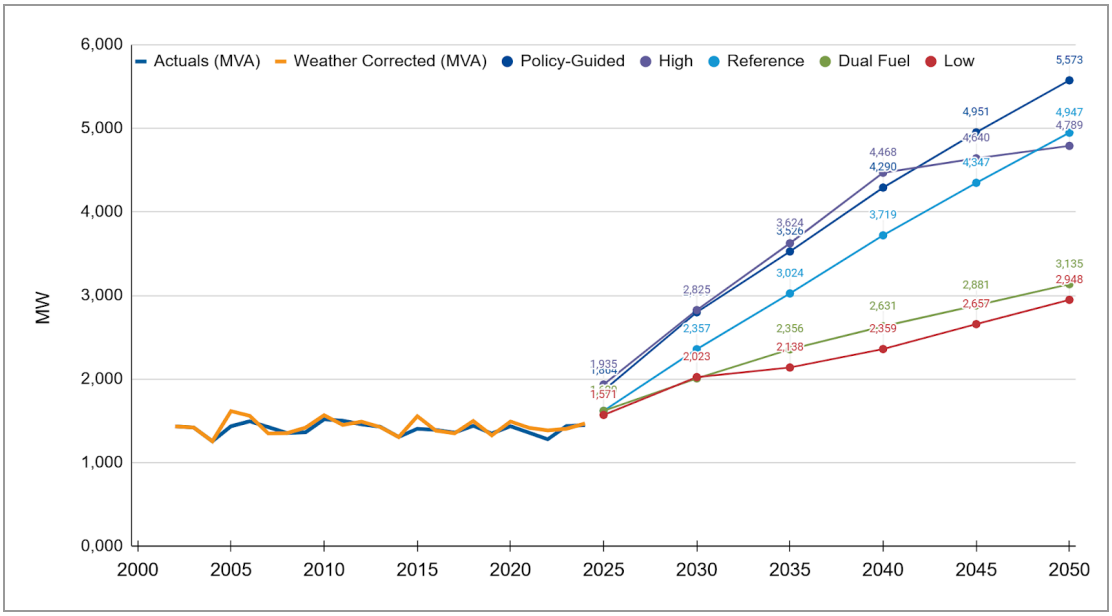
QUESTION(S):

a) Figure 114 - Decarbonization Scenario Peak by Year depicts five scenarios for electrical impact of decarbonization from 2022 to 2050. Please revise Figure 114 to provide historical actual values for 2000 to 2025.

RESPONSE(S):

a) See Figure A for the system co-incident peak historical actuals from 2002 to 2024 and the five decarbonization scenarios from 2025 to 2050. Note that actuals are available starting in 2002, and the 2025 actuals are not yet available.

Figure A: Revised Figure 114



INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-73

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 12 (pdf Exhibit 2 part 4, p. 12)

Preamble:
Hydro Ottawa states that the four investment priorities include, Growth & Electrification - Powering the Growing Community, Renewing Deteriorating Infrastructure, Grid Modernization - Enabling the Energy Transition, and Enhancing Grid Resilience. These priorities are paired with 2 foundational focuses: Managing Rising Costs and Investing in Workforce.

QUESTION(S):

a) Please explain how these investment priorities correlate to the OEB's four capital investment categories: Access, Renewal, Service and General Plant.
b) Please provide any high level capital and O&M spending targets applied by Hydro Ottawa in pursuit of the "foundational focus" of "Managing Rising Costs".
c) Does "Managing", as used here, mean passively reporting on expected cost increases or actively controlling costs?
    i) If actively, please provide examples of meaningful cost reductions Hydro Ottawa intends to implement over the 2026-2030 test period.

RESPONSE(S):

a) Table A in the response to interrogatory 1-CO-7 part (b) provides a mapping of Hydro Ottawa's investment priorities to the four OEB capital investment categories. The correlation between

Hydro Ottawa's four investment priorities and the OEB's capital investment categories can be further explained as follows:

- **Growth & Electrification - Powering the Growing Community:**
  - **System Access** investments address the need to complete an increasing number of customer connections, particularly residential and commercial developments, as well as the rising demand from large loads due to electrification (e.g., EV charging infrastructure).
  - **System Service** investments primarily enhance grid reliability and capacity, directly addressing the demands of Growth & Electrification
  - **System Renewal** investments specifically in Station Decommissioning are a necessary step to accommodate anticipated system growth and increased demand driven by electrification.
  - **General Plant** investments primarily consist of CCRA payments to Hydro One that directly correlate to the capacity projects in the system service investment category.
- **Renewing Deteriorating Infrastructure**:
  - **System Renewal** investments address the advanced age and degraded condition of a significant portion of Hydro Ottawa's infrastructure to maintain grid reliability, safety, and operational efficiency.
  - **General Plant** investments primarily consisting of Fleet Replacement provide the essential operational support and enabling infrastructure to execute grid renewal efforts. The General Plant category encompasses critical assets (like facilities and IT systems) that are not directly part of the distribution grid but are vital for supporting all essential business activities, including the planning, execution, and management of distribution infrastructure projects
- **Grid Modernization - Enabling the Energy Transition:**
  - **System Service** investments directly support grid modernization by increasing system capacity, improving observability and control, and facilitating DER integration.

- **System Renewal** investments specifically in Station Protection and Control (P&C) involve updating and replacing obsolete equipment. These modern P&C technologies are crucial for integrating advanced systems like Distributed Energy Resource Management Systems (DERMS) and supporting overall grid modernization functionalities.
- **General Plant** investments include maintaining and upgrading the software tools that directly support the modernization of grid operations listed above. This leads to improved distribution model accuracy, better operational efficiency, and reliable solutions for advanced applications

- **Enhancing Grid Resilience:**
  - System Service investments include initiatives such as strategic undergrounding of overhead lines, storm hardening, and the implementation of advanced monitoring and control capabilities to protect against extreme weather events.

b) At the outset of the budgeting process, Hydro Ottawa did not apply high-level capital or OM&A spending targets. Instead, the focus was on a comprehensive needs analysis as noted in Attachment 1-2-3(A) Corporate Memorandum - 2024-2030 Priorities and Budget Guidelines. However, as referenced in the materials from the June 2024 Board of Directors meeting (Refer to Attachment 1-CCC-13(A) - Rate Application Material Provided to the Hydro Ottawa Limited Board of Directors), this analysis showed an initial capital "need" of almost $2 billion over the five-year period. This amount was deemed to be beyond what both the company and its customers could afford.

The utility's action plan was to actively reprioritize and reduce the proposed spend. The new high-level capital target was set at approximately $1.2 billion, a reduction of 40% from the initial need. This required difficult decisions and significant cutbacks to programs such as resilience, grid modernization, strategic undergrounding, Net Zero initiatives and the ERP project, among others.

Similarly, the initial OM&A need was determined to be approximately $20 million higher than the final budget. To achieve this reduction, a reduction in the headcount was implemented (refer to

response to interrogatory 4-CCC-53 part (b) for more details), and each division was asked to identify and implement additional cost cuts to meet the new, more affordable OM&A target.

c) In this context, "Managing Rising Costs" means actively controlling and reducing costs rather than passively reporting on expected increases. This is a fundamental part of Hydro Ottawa's approach to maintaining customer affordability.

Examples of the meaningful cost reductions and productivity initiatives embedded in the application include:

- Capital Program Prioritization: Hydro Ottawa reduced its initial capital “need" of approximately $2 billion to a prioritized and affordable budget of $1.2 billion, resulting in significant spending reductions as outlined in part (b) above.
- Workforce Planning: A critical component of cost control was an 11.5% reduction in headcount from the initial OM&A plan to meet affordability targets.
- Productivity Savings: Hydro Ottawa has embedded productivity savings directly into its capital and OM&A forecasts, including minimizing inflation assumptions and deferring tariff impacts. Schedule 1-3-4 Facilitating Innovation and Continuous Improvement provides details on both quantifiable productivity savings (Section 3.0) and continuous improvement initiatives (Section 4.0).
- Inclusion of a non-wires solutions deferral account that provides funding for needed NWS programs with a transparent mechanism that provides visibility into the uncertainty within the budget programs, including unknown funding from the IESO and government agencies.
- Continuation of the capital variance account to capture provincial policy changes related to housing over the rate term for later disposition, rather than a built in assumption of higher costs.
- A five year load forecast that includes built-in electrification and large loads, providing the benefit now to customers with only a true up mechanism for unprecedented large load growth.
- An earning sharing mechanism that drives productivity and efficiencies that will also address future affordability concerns.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-74

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 36 (pdf Exhibit 2 part 4, p. 36)

Preamble:
Table 6 - System Access Capital Programs, presents system expansion as the following "This program ensures reliable electrical service to new and upgraded customer connections by strategically upgrading infrastructure like feeders, transformers, and substations to accommodate increased demand from new developments and large loads and support future growth."

QUESTION(S):

a) Hydro Ottawa classifies some system expansion investments as System Access and others as System Service. Please explain how such classification decisions are determined.

RESPONSE(S):

a) As outlined in Section 2.1 of Schedule 2-5-5 - Capital Expenditure Plan, Hydro Ottawa breaks out the expenditure plan into four Investment Categories in alignment with OEB Chapter 5 filing requirements. In particular, the following definitions used for System Access and System Service are directly aligned to the definitions provided within Section 5.1.2 of the OEB's Chapter 5 Filing Requirements.
   - System Access - Modifications (including asset relocation) to a distributor's system to provide customers (including generator customers) with access to electricity services via the distribution system.

- System Service - Modifications to the distribution system to ensure that it continues to meet the distributor's operational objectives while addressing anticipated future customer electricity demand and service requirements.

System Access Investments are primarily driven by external demands or mandated service obligations. These projects are largely initiated by external factors, meaning their timing and scope are not entirely within Hydro Ottawa's direct control, and are considered obligatory. Key drivers include customer requests for new electricity connections (like residential subdivisions, commercial developments, or connecting Distributed Energy Resources like solar). Their main purpose is to provide new or modified connections to the grid for customers, or to accommodate infrastructure projects from third parties.

In contrast, System Service Investments are driven by Hydro Ottawa's internal system needs. These projects typically originate from Hydro Ottawa's internal asset management planning and are optimized to maximize value for customers. Examples include capacity upgrades for substations and feeders, and distribution enhancements to improve system reliability and operability. Their main purpose is to upgrade and enhance the existing grid to improve its capacity, reliability, resilience, and overall modernization. Key drivers include addressing capacity constraints from load growth, enhancing the grid's ability to withstand extreme weather, and advancing grid modernization through new technologies and cybersecurity.

Please refer to Section 5.1 and Section 5.3 of Schedule 2-5-5 - Capital Expenditure Plan for more details on System Access and System Service Expenditures and their respective primary drivers.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-75

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / pp. 79-80 (pdf Exhibit 2 part 4, pp. 79-80)

Preamble:
Table 26 – System Service Expenditure Categories, provides insight as to how the Capital Programs, Budget Programs and Primary Drivers align and gives a description of the Budget Program.

QUESTION(S):

a) For all line items with the driver "Observability", please describe and quantify the resulting ratepayer benefit.
b) For all line items with the driver "Reliability", please explain if the associated investments will either maintain or improve SAIDI, SAIFI or some other reliability parameter.
    i) For each investment expected to improve reliability, please provide the cost-effectiveness of the investment in terms of risk points reduced per dollar spent.
c) For all line items with the driver "System Efficiency", please explain if the investment will reduce O&M costs, reduce losses or provide some other efficiency benefit that is meaningful to ratepayers.
    i) For each investment expected to reduce O&M costs or losses, please provide the cost-effectiveness of the investment in terms of O&M cost reduced per dollar spent or kWh of losses reduced per dollar spent, respectively.
d) How many poles will be replaced under the Capacity Voltage Conversion program during the 2026-2030 test period?
    i) Please provide the condition demographic breakdown of the poles that will be replaced under this program.

e) Please explain the apparent misalignment between the primary driver and the description.

f) If this program is not expected to reduce O&M costs, please explain why it is being undertaken.

RESPONSE(S):

a) Ratepayer benefits for programs driven by Observability are comprehensively outlined and detailed in Sections 3.4, 4.4, and 7.4 of Schedule 2-5-8 - System Service Investments.

b) For programs driven by Reliability, the impact on Reliability measures has been outlined in sections 3.2, 4.2, and 7.2 of Schedule 2-5-8 - System Service Investments. An evaluation of alternatives, including a cost-benefit analysis, is outlined in sections 3.6, 4.6, and 7.6 of the same schedule.

c)

i) Hydro Ottawa's investments in the Field Area Network (FAN) and the SCADA Upgrades Program are driven by "System Efficiency." Neither program is intended to achieve direct, quantifiable O&M cost reductions. Rather, as detailed in 2-Staff-107 and 2-Staff-33 , their purpose is to provide the critical communication network and the Advanced Distribution Management System (ADMS) required to support other grid modernization initiatives. Efficiencies associated with these programs include:

FAN Program: Physical Fiber extension and Wireless communications

- **Enables Real-time Data**: The fiber extension provides the crucial communication backbone, allowing for real-time data access from devices across the grid. This data is essential for modernizing the grid and integrating new energy resources like Distributed Energy Resources (DERs).
- **Boosts Network Reliability**: Significantly enhanced network diversity and resilience will ensure the system is less prone to outages. This leads to fewer network interruptions and faster restoration if issues do occur.

- **Improves Operational Productivity:** A robust communication infrastructure will allow for remote monitoring and control of grid assets. This reduces the need for expensive and time-consuming on-site visits and supports proactive maintenance.
- **Supports Future Grid Evolution:** The fiber extension and wireless communication offers broadband coverage that can handle high data volumes, which is necessary for future Smart Grid technologies, more DERs, and advanced metering infrastructure (AMI).

FAN Program: Management of Grid Edge Devices

- **Centralized Management and Configuration**: An Intelligent Electronic Device Management (IEDM) system provides a single, centralized platform for managing all Grid Edge Devices. This eliminates the need for manual, device-by-device configuration and maintenance, which is a source of operational cost. Hydro Ottawa will now push bulk firmware updates and security patches to a large number of devices at once, ensuring the entire fleet is up-to-date and secure. Deploy and manage new devices more quickly and efficiently. Change operational settings remotely, without the need for a "truck roll" (sending a crew to the field).
- **Asset Management and Lifecycle Control:** IEDM systems provide a comprehensive view of all IEDs on the network, including their location, firmware version, and configuration. This improves asset management by providing accurate and real-time inventory of all intelligent devices, enables the tracking of the entire lifecycle of each device, from deployment to retirement and helps with maintenance and replacement planning.
- **Enhanced Cybersecurity**: Grid Edge Devices are critical components of the smart grid, and their security is paramount. IEDM systems provide centralized security management, which includes automated security audits and vulnerability checks, centralized user management and access control and detailed logging of all device access and configuration changes, which is vital for regulatory compliance (e.g., NERC CIP).

FAN Program: Cybersecurity

- **Enhanced Situational Awareness**: This initiative involves real-time monitoring and logging of network activity. This provides a deep level of visibility into the health and status of the SCADA network and the devices it controls. This enhanced awareness helps Hydro Ottawa identify not only cyber threats but also potential operational anomalies or equipment failures that might otherwise go unnoticed.
- **Avoidance of Catastrophic Costs**: The most significant financial efficiency of improved cybersecurity is the prevention of a major cyberattack. A successful attack on a SCADA network could lead to physical damage to equipment, widespread power outages, and financial losses from service disruption. By investing in cybersecurity, a utility avoids these potentially crippling costs.
- **Enabling Digital Transformation**: As Hydro Ottawa adopts more modern technologies like the Internet of Things (IoT) and cloud computing, the attack surface grows. A strong cybersecurity foundation is essential for safely and efficiently integrating these technologies, which are key to future operational efficiencies and new business models.

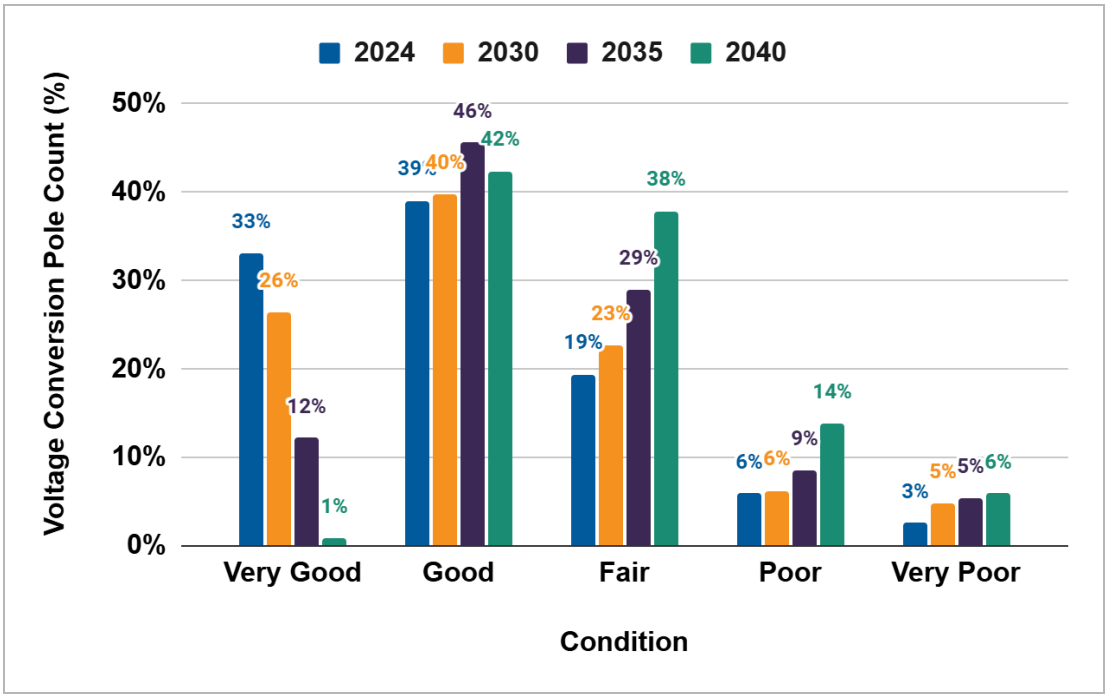
SCADA Upgrades Program

- **Unified Platform and Streamlined Operations:** SCADA upgrades integrated with ADMS will create a single, cohesive platform that simplifies data management, reduces potential points of failure, and streamlines system configuration and maintenance

d) Approximately 1,934 poles will be replaced through the EOL voltage conversion program between 2026-2030, out of which 1,708 poles are owned by Hydro Ottawa. The main driver of this voltage conversion program is the condition and age of the station assets (mainly station transformers and breakers) at select 4 kV stations as discussed in Section 2.3.3 Station Transformers under Schedule 2-5-7 - Systems Renewal Investments, with additional capacity limitations identified in the region.

i) Hydro Ottawa only has condition information for the Hydro Ottawa-owned poles to be replaced as a part of the EOL voltage conversion program. Projections for the condition of these poles, extending to 2040, are presented in Figure A.

Figure A - Condition Profile Projection of EOL Voltage Conversion Poles



e) Hydro Ottawa identifies a correction for the description of the Distribution System Resiliency Budget Program in Table 26 in Schedule 2-5-5 - Capital Expenditure Plan. The correct description for Distribution System Resiliency, with the primary driver of Resilience, should be: Enhancements to the distribution system's resilience, enabling it to better withstand and rapidly recover from extreme weather or unexpected events. This includes undergrounding of overhead lines, hardening existing overhead lines, relocating lines, and reconfiguring feeders.

f) Hydro Ottawa is unable to directly answer the question due to the ambiguity surrounding the specific program being referenced in Table 26, as it lists multiple programs that both increase and decrease O&M costs. For more information regarding the impact on O&M costs due to System Service programs, refer to Section 6.3.3 of Schedule 2-5-5 - Capital Expenditure Plan.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-76

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 91 (pdf Exhibit 2 part 4, p. 91)
Ref. 2: Exhibit 2 / Tab 5 / Schedule 8 / p. 77 (pdf Exhibit 2 part 4, p. 441)

Preamble:
Hydro Ottawa states that 30% of the budget is allocated to Reliability (feeder reconfiguration and phase balancing) and Enhancement (DER integration through infrastructure upgrades and pilot projects).

Hydro Ottawa also states the following for Feeder Phase Balancing: “This program will optimize the distribution of electrical load across the system through feeder phase balancing. This will ensure that each phase of a three-phase feeder carries a similar amount of current, minimizing power losses due to imbalances. This optimization will also reduce stress on equipment, prolonging the lifespan of grid assets and reducing the need for premature replacements.”

QUESTION(S):

a) Is phase balancing an O&M or capital activity? Please explain.
b) Please explain why Feeder Phase Balancing is not typically done as an ongoing O&M activity as new single-phase loads are added to feeders.

RESPONSE(S):

a) Phase balancing can be classified as either an Operating and Maintenance (O&M) or a capital activity, contingent on the scope of work. If the activity involves adding new assets, such as a

switch, to complete the phase balancing, it is considered a capital expenditure. Conversely, if phase balancing is achieved solely through the operation of existing switching devices, it falls under O&M. The key distinction lies in whether the activity optimizes and maintains the current system (O&M) or involves an investment that enhances or expands the system's fundamental capacity or longevity (capital).

b) Hydro Ottawa treats feeder phase balancing as an ongoing O&M activity whenever applicable. When new single-phase loads are added, we review existing phase loading on the supply feeder to strategically connect the loads, ensuring better balance across the feeder.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-77

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 36 (pdf Exhibit 2 part 4, p. 36)

QUESTION(S):

a) With regards to bulk metered buildings that contain multiple residential residences that were upgraded to suite metering, in the historic period.
   i) How many bulk metered buildings were retrofit with suite metering by Hydro Ottawa, per year?
   ii) How many residential customers were connected to suite metering due to the retrofit of a bulk metered building to include suite metering by Hydro Ottawa, per year?

b) How many additional individually suite metered customers has Hydro Ottawa forecast for the forecast period, through the retrofitting of existing bulk metered buildings that contain multiple residential residences, per year.

RESPONSE(S):

a) Please see Table A below for responses to questions i) and ii), for the historical years to the end of 2024.

Table A - 2021-2025 Retrofit Suite Metering

Year	# of Buildings	Residential Units
2019	1	61
2020	3	90
2021	8	181
2022	3	202
2023	1	351
2024	4	420

b) Hydro Ottawa did not have a specific forecast of buildings or customers as a result of converting bulk metered buildings to suite-metering for the Test Years. Known suite metering projects were included in the Bridge Years, and historical trending was used to forecast Test Year capital amounts.

From a revenue forecast perspective, as stated in Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast to Schedule 3-1-1 - Revenue Load and Customer Forecast

> "Hydro Ottawa provided Itron data showing the annual reclassification from bulk meters to individual unit meters. Before 2019, many multi-unit residential buildings were bulk metered as one commercial account; this has since changed, with some units being individually unit metered. This is occurring in the construction of new multi-unit buildings as well as retrofitting existing buildings. In 2020, 6,454 new customers were added, followed by 6,810 in 2021, considerably higher than the prior year averages of approximately 4,000. Since 2021, growth has slowed but is still above historical averages, 5,284 customers were added in 2023. Population growth is expected to remain high in 2024 with 2.3% growth, followed by 1.5% in 2025 before falling to 1.0% or below after 2026.
>
> The customer forecast is based on a monthly regression model that relates the number of customers to a blended economic variable, using both population and gross domestic

product (GDP); the correlation between the number of customers and the blended economic variable is extremely high at 0.99. This improved methodology is a change from the prior forecast and helps explain the historical changes in customer growth since 2020."

This updated forecasting methodology looked at both retrofit bulk metered customers and new buildings that were suite metered.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-78

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / pp. 50, 51 (pdf Exhibit 2 part 4, pp. 50, 51)
Ref. 2: Final Notice of Amendments to the Distribution System Code, June 16, 2025

Preamble:
Hydro Ottawa states the that the "updates to capital contributions as a result of OEB's recent policy changes in System Expansion for Housing Developments (EB-2024-0092) have not incorporated" in the forecast capital contributions in Table 11 or Table 12 of reference 1.

Appendix C of reference 2 outlines changes to the Distribution System Code to extend the customer revenue horizon to 40 years for residential customers (as defined in Appendix C).

QUESTION(S):

a) Please update Table 11 and Table 12 with revised amounts due to the change in the customer revenue horizon to 40 years.
    i) Please provide supporting calculations detailing how Hydro Ottawa arrived at the revised values.
    ii) Please include in the supporting calculations an example of at least one specific development request, which can be an actual request with identifying information removed, or an illustrative development request that would be similar to those typically received by Hydro Ottawa.

RESPONSE(S):

In an effort to be responsive to the request, Hydro Ottawa has provided the following analysis that is hypothetical and is not the experience of managing the actual impacts of the recently released Distribution System Code (DSC) Amendments. Hydro Ottawa also notes that each residential development can be impacted by geographical conditions and unique customer requirements, which is then further impacted by how developers are going to approach the DSC amendment in future requests. As such, although an example has been provided, this should not be understood as a "typical" request, as requests tend to be unique and for the reason stated above and are evolving. Please also see response to interrogatory 2-CCC-20 for further information surrounding Residential Subdivision forecasting.

a) Table A (i.e. Table 11 in Schedule 2-5-5 - Capital Expenditure Plan) below provides forecasted System Access Expenditures by program for 2026-2030 based on original submission. Table B below provides forecasted capital contributions with revised amounts due to the change in the customer revenue horizon to 40 years (illustrative purpose only). Table C (System Access Capital Contributions difference) below provides a forecasted capital contribution difference by program between Table A and B. Table D (i.e. Table 12 in Schedule 2-5-5 - Capital Expenditure Plan) and Table E below provide System Access contributions by program for 2026-2030 based on original submission, and illustrative revised amounts due to the change in the customer revenue horizon to 40 years respectively.

Table A – System Access Expenditures by Capital Program (Original Submission) ($'000s)

Capital Program	Test Years					
	2026	2027	2028	2029	2030	Total
Plant Relocation	$ 6,605	$ 6,707	$ 7,062	$ 7,193	$ 7,390	$ 34,957
System Expansion	$ 46,227	$ 20,060	$ 14,273	$ 15,034	$ 15,224	$ 110,818
Customer Connections	$ 32,318	$ 50,839	$ 43,673	$ 43,471	$ 47,459	$ 217,759
Generation Connections	$ 696	$ 753	$ 835	$ 924	$ 1,033	$ 4,241
Metering	$ 323	$ 332	$ 347	$ 356	$ 367	$ 1,724
GROSS SYSTEM ACCESS	**$ 86,169**	**$ 78,690**	**$ 66,190**	**$ 66,978**	**$ 71,472**	**$ 369,500**
Capital Contribution	$ (43,968)	$ (43,034)	$ (37,213)	$ (31,502)	$ (40,555)	$ (196,272)
NET SYSTEM ACCESS	**$ 42,202**	**$ 35,656**	**$ 28,977**	**$ 35,476**	**$ 30,917**	**$ 173,228**

Table B – System Access Capital Expenditures Program (Incorporating Impacts of DSC Amendment) ($'000s)

Capital Program	Test Years					
	2026	2027	2028	2029	2030	Total
Plant Relocation	$ 6,605	$ 6,707	$ 7,062	$ 7,193	$ 7,390	$ 34,957
System Expansion	$ 46,227	$ 20,060	$ 14,273	$ 15,034	$ 15,224	$ 110,818
Customer Connections	$ 32,318	$ 50,839	$ 43,673	$ 43,471	$ 47,459	$ 217,759
Generation Connections	$ 696	$ 753	$ 835	$ 924	$ 1,033	$ 4,241
Metering	$ 323	$ 332	$ 347	$ 356	$ 367	$ 1,724
GROSS SYSTEM ACCESS	**$ 86,169**	**$ 78,690**	**$ 66,190**	**$ 66,978**	**$ 71,472**	**$ 369,500**
Capital Contribution	$ (43,393)	$ (42,421)	$ (36,550)	$ (30,793)	$ (39,797)	$ (192,955)
NET SYSTEM ACCESS	**$ 42,776**	**$ 36,269**	**$ 29,640**	**$ 36,185**	**$ 31,675**	**$ 176,545**

Table C – System Access Capital Contributions difference ($'000s)

Capital Program	Test Years					
	2026	2027	2028	2029	2030	Total
Plant Relocation	$ -	$ -	$ -	$ -	$ -	$ -
System Expansion	$ -	$ -	$ -	$ -	$ -	$ -
Customer Connections	$ (574)	$ (613)	$ (663)	$ (709)	$ (757)	$ (3,317)
Generation Connections	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL CAPITAL CONTRIBUTIONS	**$ (574)**	**$ (613)**	**$ (663)**	**$ (709)**	**$ (757)**	**$ (3,317)**

Table D – System Access Capital Contributions by Capital Program (Original Submission) ($'000s)

Capital Program	Test Years					
	2026	2027	2028	2029	2030	Total
Plant Relocation	$ (3,788)	$ (3,843)	$ (3,988)	$ (4,076)	$ (4,180)	$ (19,874)
System Expansion	$ (21,937)	$ (9,044)	$ (8,667)	$ (2,676)	$ (9,265)	$ (51,589)
Customer Connections	$ (17,552)	$ (29,401)	$ (23,741)	$ (23,843)	$ (26,097)	$ (120,634)
Generation Connections	$ (690)	$ (747)	$ (817)	$ (908)	$ (1,013)	$ (4,175)
TOTAL CAPITAL CONTRIBUTIONS	**$ (43,968)**	**$ (43,034)**	**$ (37,213)**	**$ (31,502)**	**$ (40,555)**	**$ (196,272)**

Table E – System Access Capital Contributions by Capital Program (Updated for DSC Amendment) ($'000s)

Capital Program	Test Years					
	2026	2027	2028	2029	2030	Total
Plant Relocation	$ (3,788)	$ (3,843)	$ (3,988)	$ (4,076)	$ (4,180)	$ (19,874)
System Expansion	$ (21,937)	$ (9,044)	$ (8,667)	$ (2,676)	$ (9,265)	$ (51,589)
Customer Connections	$ (16,978)	$ (28,788)	$ (23,077)	$ (23,133)	$ (25,340)	$ (117,317)
Generation Connections	$ (690)	$ (747)	$ (817)	$ (908)	$ (1,013)	$ (4,175)
TOTAL CAPITAL CONTRIBUTIONS	**$ (43,393)**	**$ (42,421)**	**$ (36,550)**	**$ (30,793)**	**$ (39,797)**	**$ (192,955)**

i) To support the revised values for 2026-2030 contributions, Hydro Ottawa sampled large projects completed in 2022-2024 that would be eligible for the 40-year revenue horizon under the amendment. For each sample predominately residential project, a comparison of the contributions calculated for a 25-year or 15-year revenue horizon (for residential or non-residential connection respectively) under the OEB's prescribed economic evaluation methodology were compared against the contributions calculated using a 40-year revenue horizon under the same methodology. All other inputs in the contributions calculation were kept the same as the original calculation. The results from the calculation using the 40-year horizon were then compared against the results using the original revenue horizon to determine the expected change. The impact was then extrapolated across total program spending based on the sample group's proportion of total spend for 2022-2024 to estimate the total potential impact.

ii) Table E below shows an illustrative non-residential connection that would be impacted by the DSC amendment that extended the customer revenue horizon to 40 years for residential customers based on 2025 rates and cost.

Economic Evaluation (EE) Calculation inputs considered

- Residential building with 100 units
- Estimated monthly peak of 112kW (GS 50-1,499 kW)
- Fixed rate $200.00 (2025 rates)

- Variable rate $6.5553 (2025 rates)
- Original revenue horizon 15 years
- Revised Revenue Horizon- 40 years

Table E- Illustrative Non-Residential Connection EE Calculation

Residential building - bulk metered	15 years	40 years	Variance
Connection costs	50,000	50,000	0
System expansion cost	141,000	141,000	0
System expansion credit (NPV of EEC)	(40,000)	(68,000)	(28,000)
Capital contribution	101,000	73,000	(28,000)
Capital contribution as % to system expansion cost	71.63%	51.77%	(19.86)%

The below table illustrates the related first year impact on revenue requirement impact as capital contributions are expected to be less due to this DSC amendment and is based on:

1. Depreciation using half year rule for pooled assets
2. Weighted distribution asset life of 36 years
3. Accelerated CCA
4. Proposed cost of capital
5. Exclude impact on proposed PILs CC
6. Exclude change to cost allocation
7. Exclude impact on OM&A

Table F- Illustrative Impact on Revenue Requirement of a Single Non-Residential Developement

	$
Increase in rate base	14,000
Increase in depreciation	389
Increase in return on rate base (WACC 5.97%)	813
Increase in Income Taxes (G/U)	(491)
Change in service revenue requirement	**14,711**

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-79

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 70-71 (pdf Exhibit 2 part 4, pp. 70-71)

Preamble:
Hydro Ottawa stated that the five year budget reflects a shift towards targeted, efficient upgrades, particularly in response to increasing obsolescence and technological advancements. Some of the programs include End of Life (EOL) Voltage Conversion Program, Station Transformer Renewal, and Station Switchgear Renewal.

QUESTION(S):

a) These three programs would all appear to support reduced O&M since they will presumably replace deteriorated high-maintenance assets with new low-maintenance assets, and in the case of voltage conversions, should reduce the total asset count by eliminating urban stations. Please confirm if this is true and discuss.
b) Please indicate what O&M reductions are forecast.

RESPONSE(S):

a) The proposed decommissioning/elimination of 4 kV stations (resulting in a reduction of total asset count) and replacement of the high-risk station switchgear/breakers (including one station transformer) does not support reduced O&M costs. Section 2.3.2 Renewing Deteriorating Infrastructure (Table 3) of Schedule 2-5-1: Distribution System Plan Overview, estimates the investment required to replace all station batteries, breakers, and transformers projected to be in degraded condition by 2030 at $205M (Per Table 3 of Schedule 2-5-1); however, due to

competing financial priorities—including growth, electrification, grid modernization, and resilience—this level of investment is impractical. Hydro Ottawa therefore proposes a risk-balanced investment approach of $90M for the 2026-2030 period (Per Table 3 of Schedule 2-5-1), with an additional $17.7M allocated for relays, RTUs, minor station assets, buildings/facilities, and transfer trip installations, as shown in Table 3 of Schedule 2-5-7 - System Renewal Investments. Consequently, Hydro Ottawa will need to prioritize O&M spending to maintain asset performance, address the backlog of deteriorated station assets not slated for replacement by 2030, and sustain station assets planned for renewal between 2026-2030 as part of multi-year replacement strategies. Also, there are newly proposed OM&A activities related to the EOL voltage conversion program and the 4 kV station decommissioning between 2026-2030 for a total of $3.1M. More information regarding OM&A is highlighted in par (c) of Hydro Ottawa's response to interrogatory 4-CCC-40.

b) There are no major O&M reductions being forecasted. Please refer to part a) above for justification, as well as the part c) of the response to interrogatory 2-Staff-43.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-80

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 93 (pdf Exhibit 2 part 4, p. 93)

Preamble:

Table 30 – General Plant Capital Programs, provides the following information concerning Grid Technology:

> This program addresses the maintenance and upgrade of tools and software that supports modernization of grid operations, integrates new technologies like DERs and supports grid planning. The program focuses on network visualization and management, data collection and archiving, and network modelling and simulation.

QUESTION(S):

a) Please explain why these investments would not be categorized as System Service.

RESPONSE(S):

The OEB Filing Requirements Chapter 5 provides clear definitions that guide Hydro Ottawa's asset classification:

- System Service investments are defined as "...modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements."

- General Plant investments are defined as "...modifications, replacements or additions to a distributor's assets that are not part of its distribution system including...electronic devices and software used to support day to day business and operations activities."

Systems included in the Grid Technology General Plant program support the day-to-day operations such as network visualization and management, data collection and archiving and model simulation but are not directly connected to Hydro Ottawa's distribution system.

This falls under the OEB's definition of General Plant as assets that are "…not part of its distribution system" and "...electronic devices and software used to support day to day business and operations activities." This classification is also consistent with the 'Business Operations Support' investment driver for General Plant, as outlined in Table 9 of Schedule 2-5-4 - Asset Management Process.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-81

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 38 (pdf Exhibit 2 part 4, p. 38)

Preamble:
Table 8 - System Access Historical & Bridge Spending versus OEB Approved ($'000s), shows Generation Connections has an OEB-Approved capital expenditure of $1,578 over 2021-2025 and a Historical/Bridge capital expenditure of $525 over 2021-2025.

QUESTION(S):

a) What drove generation connection expenditures to fall to 1/3 of forecast?
b) Could the same or similar factors cause forecast spending on generation connections to fall similarly below forecast for the 2026-2030 test period? Please discuss.

RESPONSE(S):

a) The Generation Connections program is inherently driven by customer demand. Hydro Ottawa believes that economic factors may have resulted in lower than expected customer demand for project execution. Spending was higher than budgeted in 2021, but a drop in customer requests for new generation connections from 2022 to 2025 led to a net underspend of $0.5 million. This decline in demand is most likely attributed to economic factors such as the Bank of Canada's interest rate hikes which increased borrowing costs, and rising inflation which drove up the cost of materials for these projects. For more details on historical variances please refer to page 48, Section 5.1.2 of Schedule 2-5-5 - Capital Expenditure Plan.

b) Hydro Ottawa does not anticipate that the same or similar factors will cause underspend in the 2026-2030 test period and forecasts a likely increase in investment for this category, based on indications as listed below:

- **Anticipated Acceleration in DER Adoption:** The 2026-2030 forecast is built on the expectation of accelerated adoption of DERs. Hydro Ottawa has seen an increased number of DER preliminary consultation requests and connection impact assessment (CIA) requests in 2024 and the trend continues in 2025. Please refer to Figure 13 in Schedule 2-5-1 - Distribution System Plan Overview. This speaks to increased DER adoption that will be seen in the coming years when these requests move to project execution.

- **Incentive Programs:** Hydro Ottawa has seen a significant surge in requests attributed to the IESO's Ottawa DER Large Solar PV Funding Incentive program launched in January 2024. The program's expansion to province-wide customers in January 2025 suggests that this trend will likely persist. These incentive programs are clearly stimulating public interest and participation in DER. More details in Section 2.4 of Schedule 1-4-1 - Customer Engagement Ongoing.

- **Large Scale Assumption:** Based on the increased DER adoption trends mentioned in the above two points, Hydro Ottawa's budget forecast incorporates an assumption of at least one large DER connection (above 500 kW) per year between 2026 and 2030.

While the 2021-2025 period saw an underspend due to economic pressures that followed the pandemic, the forecast for 2026-2030 is supported by renewed incentives and a projected increase in customer-driven DER adoption, leading to an expectation of accelerated investment in Generation Connections.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-82

EVIDENCE REFERENCE:

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

Preamble:
Table 22 - OH Unit Asset Renewal Comparison per OH Asset Class, shows an increase in asset replacements from the historic/bridge period to the forecast period; OH transformer renewals are planned to increase from 309 to 400 and OH switch / recloser renewals are planned to increase from 56 to 340.

QUESTION(S):

a) Please describe the typical triggers for OH transformer replacement and the percentage of renewals driven by each trigger.
b) Please provide a table comparing the age and condition demographics of OH Switches & Reclosers as of 2020 and the latest available.
c) If the count of OH Switches & Reclosers in poor or very poor condition is not six times higher than was the case in 2020, please explain the proposed step change in proactive replacements.

RESPONSE(S):

a) Hydro Ottawa installs, replaces and upgrades overhead transformers due to various drivers described in Table A, corresponding with the Ontario Energy Board's (OEB) investment categories.

Table A: Drivers for Distribution Overhead Transformer Installation / Replacement / Removal

OEB Investment Category	Driver Description	Percentage of Renewal Triggered (based on 2021-2025)
System Access	Upgrade an existing overhead transformer to support service equipment New overhead transformers installed to support service equipment – temporary and permanent Relocate overhead transformers, typically driven by the relocation of the support pole, to accommodate work (e.g. new developments, road expansions) and eliminate clearance concerns	47.5%
System Renewal	Overhead transformers replaced due to risk and condition (both planned, critical and emergency) Overhead transformers damaged by third parties e.g. vehicle accident	47.5%
System Service	New or upgraded overhead transformers to improve reliability New or upgraded overhead transformers to alleviate capacity constraints New or upgraded overhead transformers to support voltage conversion	5%

From Table A, it can be seen that System Access and System Renewal programs are the predominant triggers for overhead transformer replacements, followed by System Service (based on 2021-2025 information). There is no exclusive planned budget program allocated for overhead transformers and they are proposed to be replaced as a part of the pole inspection program. Poles and overhead transformers have a similar typical useful life of 53 years. As a part of the pole inspection program, Hydro Ottawa validates the condition of the relevant overhead transformer on-site and completes the overhead transformer replacement (if deemed necessary). Therefore, Hydro Ottawa takes advantage of the pole replacement program to replace overhead transformers that are found to be degraded.

b) For overhead switches and reclosers, data is not available for age demographics and condition data in 2020 as explained in Section 2.1 of Schedule 2-5-1 - Distribution System Plan. Please see Table B below for 2024 recloser age demographics (in terms of typical useful life (TUL)) and Table C for recloser conditions in 2024.

Table B - 2024 Recloser Age Demographics

Asset Class	Age Demographics - 2024	No. of Assets
Recloser	Less than 10 years of TUL remaining	2
Recloser	More than 10 years of TUL remaining	41

Table C - 2024 Reclosers Condition Profile

Asset Class	Condition	No. of Assets
Recloser	Very Good	7
Recloser	Good	36

For overhead switches, condition information is available for 2020 only for critical switches, as shown in Table D. Note that those categorized as an “invalid” condition did not undergo a condition assessment, and therefore could not be categorized.

Table D - 2020 Overhead Critical Switches Condition Profile

Asset Class	Condition	No. of Assets
Overhead Critical Switches	Very Good	23
	Good	20
	Fair	8
	Invalid	143

Please see Table E below for 2024 overhead switch demographics and Table F for 2024 overhead switch condition profile. Please refer to Section 7.1.2.3 of Schedule 2-5-4 - Asset Management Process for more information on overhead switch demographics.

Table E - 2024 Overhead Switch Demographics

Asset Class	Age Demographics- 2024	No. of Assets
Overhead Switches	Reached or Exceeded TUL	81
	Less than 10 years of TUL remaining	199
	More than 10 years of TUL remaining	3303

Table F - 2024 Overhead Switch Condition Profile

Asset Class	Condition	No. of Assets
Overhead Switches	Very Good	2,759
	Good	737
	Fair	16
	Poor	59
	Very Poor	12

c) The condition data for overhead switches is still evolving and there are proposed maintenance enhancements as a part of 2026-2030 to improve the quality of condition information. This is discussed in Section 3.1 of Schedule 4-1-2: Operations, Maintenance and Administration Program Costs. Despite evolving condition data, the overhead switch renewal program has significantly increased compared to the historic period because of the following factors, as outlined in Section 3.6.3 Preferred Alternative of Schedule 2-5-7 - System Renewal Investments:

- **Historical Outages:** There's a relatively high number of annual outages (average of 32 outages per year between 2021 and 2025) due to OH switchgear, indicating a current reliability issue.
- **Future Backlog:** Without intervention, a sharp increase in OH switches reaching their Typical Useful Life (TUL) is projected, with 12% by 2035 and over half (54%) by 2040. Initiating a proactive replacement program through 2026-2030 helps prevent a significant backlog in the future.

- **Lack of Correlation between Condition and Outages:** The current condition information on overhead switches doesn't consistently correlate with outage data, suggesting that solely relying on current condition data isn't sufficient to predict failures.
- **Grid Modernization:** The overhead switch/recloser renewal program includes incremental investments to convert manual switches to remote controllable switches, which will improve system observability and controllability, supporting Hydro Ottawa's grid modernization efforts.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-83

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 75 (pdf Exhibit 2 part 4, p. 75)

Preamble:
Table 23 - UG Unit Asset Renewal Comparison per UG Asset Class, shows that Vault Transformer Renewals are expected to increase from a total of 18 in the historical/bridge period to a total of 90 in the forecast period.

QUESTION(S):

a) Please provide a table comparing the age and condition demographics of Vault Transformers as of 2020 and the latest available data.
b) If the count of Vault Transformers in poor or very poor condition is not five times higher than was the case in 2020, please explain the proposed step change in proactive replacements.

RESPONSE(S):

a) 2020 condition data is not available for vault transformers as described in Section 2.1 of Schedule 2-5-1 - Distribution System Plan. Please see Table A below for 2020 Vault Transformer Age Demographics.

Table A - 2020 Vault Transformers Age Demographics

Asset Class	Age Demographics	No. of Assets
Vault Distribution Transformer	More than 10 years of TUL remaining	2,216
	Less than 10 years of TUL remaining	947
	Reached or Exceeded TUL	489

For 2024 vault transformer age demographics please see Table B below. Table C below shows 2024 vault transformer condition. Please refer to Section 7.1.3.5 of Schedule 2-5-4 - Asset Management Process for more information.

Table B - 2024 Vault Transformers Age Demographics

Asset Class	Age Demographics	No. of Assets
Vault Distribution Transformer	More than 10 years of TUL remaining	2,389
	Less than 10 years of TUL remaining	1,140
	Reached or Exceeded TUL	982

Table C - 2024 Vault Transformers Condition Demographics

Asset Class	Condition	No. of Assets
Vault Distribution Transformer	Very Good	653
	Good	1,156
	Fair	1,068
	Poor	1,044
	Very Poor	590

b) Hydro Ottawa advanced its vault equipment inspection program in 2024 to capture component-level information and remains committed to further investment in proposed inspection enhancements through 2026-2030, as detailed in Section 3.1 of Schedule 4-1-2 - Operations, Maintenance, and Administration Program Costs. Despite evolving condition data, increased investment in the vault renewal program, specifically for vault transformers, is crucial due to the following factors, as outlined in Section 4.6.3 of Schedule 2-5-7 - System Renewal Investments:

- **Overall Aging Portfolio:** Hydro Ottawa-owned vault equipment (both transformers and switchgear) is reaching end-of-life, with a significant projected increase in end-of-life vault transformers (approximately 42% by 2030), as indicated in Section 4.3.5 of Schedule 2-5-7 - System Renewal Investments.
- **Increased Failure/Outage Response Impact:** Hydro Ottawa has encountered growing difficulties in replacing vault equipment or accessories (e.g., bushings) during outages caused by vault transformer failures, primarily due to space limitations in customer-owned vaults. These failures have also necessitated recourse to the Emergency Renewal budget program, as outlined in Section 6 of Schedule 2-5-7 - System Renewal Investments.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-84

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / pp. 78-78 (pdf Exhibit 2 part 4, pp. 77-78)

Preamble:
"Hydro Ottawa's System Service Investments are broken out into six capital programs", Capacity Upgrades, Distribution Enhancements, Station Enhancements, Grid Technologies, Control and Optimization and Field Area Network.

QUESTION(S):

a) Please sort planned System Service spending initiatives into the following primary justification bins:

- Improves system reliability
- Maintains system reliability
- Expanding system capacity
- Reduces O&M costs
- Other (please identify justification for all "Other" spending initiatives above the $1M materiality threshold.

RESPONSE(S):

a) The System Service investments aim to enhance grid reliability and capacity, ensuring the system continues to meet operational goals and future customer demands, particularly concerning electrification and grid resilience, as stated in Section 3.3 of Schedule 2-5-5 - Capital Expenditure Plan. The rationale for each System Service investment is provided in the "Primary

Driver" column of Table 26 in Section 5.3 of the same Schedule. These investments are categorized into the 2-Staff-84(a) justification bins as follows:

Improves system reliability

- Distribution Enhancement
- Stations Enhancement
- Distribution System Reliability

Maintains system reliability

- There are no specific System Service initiatives whose primary justification is solely to maintain existing reliability levels - all reliability-focused investments within System Service are designed to improve the system's resilience, observability, and overall performance.

Expanding system capacity

- Station Capacity Upgrades
- Distribution Capacity Upgrades
- Non-Wire Upgrades
- Capacity Voltage Conversion

Reduces O&M costs

- There are no specific System Service initiatives whose primary justification is solely to reduce O&M costs. Enhanced system observability through Grid Technologies and Station Enhancements provides real-time data on asset health and performance. This allows for proactive identification of potential issues, enabling preventative maintenance and reducing unexpected failures, thereby avoiding more expensive emergency repairs and associated restoration costs.

Other - Observability

- Distribution System Observability
- RTU Upgrades

- SCADA Upgrades
- Control and Optimization

Other - Resilience

- Distribution System Resilience

Other - System Efficiency

- Physical Fiber Extension
- Wireless Communication
- Management of Grid-Edge Device
- SCADA Network Cyber Security

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

2-Staff-85

EVIDENCE REFERENCE:

Ref. 1: Exhibit 2 / Tab 5 / Schedule 5 / p. 88 (pdf Exhibit 2 part 4, p. 88)

Preamble:
Table 29 – System Service Forecast Expenditures by Capital Program ($'000s), shows that the Capacity Upgrades program is forecast to increase from $108,244 in the historical/bridge period to $346,890 in the forecast period, and Field Area Network is forecast to increase from $1,947 in the historical/bridge period to $20,750 in the forecast period.

QUESTION(S):

a) Please quantify the risk that some portion of the planned capacity upgrade investments will be stranded or redundant if the aggressive load growth trajectory does not materialize as forecast.
b) Please provide the total program expenditures that would have occurred from 2021 - 2025 had the program proceeded as initially planned.
c) Would the need for capacity upgrades spending be significantly impacted by higher or lower rates of load growth?
    i) If yes, please provide the sensitivity analysis Hydro Ottawa performed to evaluate the risk of stranding upgrade capital should the forecast load growth not occur.

RESPONSE(S):

a) As outlined in Section 9.1 of Schedule 2-5-4 - Asset Management Process, the Hydro Ottawa Planning Forecast was used to assess the immediate needs of the system focused on already constrained regions and areas with immediate, confirmed, and committed load requirements

necessary to meet customer service obligations. In addition, Hydro Ottawa utilized the Decarbonization Study's Reference Scenario forecast to inform its Integrated Regional Resource Plan (IRRP) forecast. This alignment is crucial for long-term regional transmission planning, given the extended lead times of transmission grid investments. Furthermore, Hydro Ottawa leveraged this IRRP forecast derived from the Decarbonization Study's Reference scenario to augment its own investment decisions for efficient capital deployment and optimizing asset utilization. In line with this approach, Hydro Ottawa is confident that the planned capacity upgrades face no risk of becoming stranded or redundant. Hydro Ottawa remains committed to closely monitoring the realization of its Planning forecast and the IRRP forecast and making adjustments to its capital investments as required.

b) Had the program proceeded as initially planned, the total expenditures would have been the OEB-Approved budget of $75.8M for Capacity Upgrades and $6.1M for Field Area Network as shown in Table 27 of Schedule 2-5-5 - Capital Expenditure Plan. Please refer to Capacity Upgrades and Field Area Network in Section 5.3.2 of Schedule 2-5-5 - Capital Expenditure Plan for the primary drivers causing the 43% and 68% variance from initial plan.

c) The need for capacity upgrades spending would be impacted by significantly higher rates of growth, as increased load growth necessitates higher spending on capacity upgrades. However, as mentioned in the response to question (a) above, the risk to underutilizing station capacity upgrades due to lower than expected load growth rates is very low, as capacity upgrade spending is linked to immediate needs of the system driven by capacity constraints and committed load.